Corrosion

Official Publication
NATIONAL ASSOCIATION OF CORROSION ENGINEERS

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DETROIT

Vol. 13 MAY, 1957 No. 5

YOU CAN'T KNOW

what the real price tag is...

How price per gallon compares on leading vinyls

Amercoat 33HB	Brand A	Brand B	Brand C
100%	81%	117%	54%

UNLESS YOU

compare mil sq. ft. per gallon and...

Sq. ft. coverage per gallon, 1 mil thick

33HB	464
A	265
B	320
C	194

FIGURE THE

material cost of each coating, then get the...

Needed to coat 250 sq. ft. 5 mils thick

	GALS.	COST
33HB	2.68	$17.37
A	4.72	24.78
B	3.91	29.72
C	6.44	22.54

REAL COST

by adding labor for the number of coats needed.

Labor & material cost, 250 sq. ft. x 5 mils thick

33HB	$37.47
A	60.18
B	59.05
C	70.84

Announcing...

A True High Build Vinyl Coating

Amercoat 33HB now gives you even *more* "mils per gallon" —and at the lowest cost of any leading vinyl!

At last, the two major limitations of vinyl protective coatings—critical adhesion and low film thickness—have been largely overcome. Amercoat 86 Primer stopped adhesion troubles, eliminated underfilm corrosion and undercutting, and simplified surface preparation. *Now Amercoat 33HB Topcoat builds thick films in fewer coats at surprising savings.*

Amercoat 33HB is a "high-build" version of Amercoat 33, the standard of the protective coatings industry for over ten years. 33HB gives you the same high resistance to corrosive chemicals, severe weathering and abrasion, *plus 33% greater thickness per coat!*

The solids content of 33HB tops all other non-mastic vinyl coatings, yet workable viscosity is retained. It applies smoothly and easily by hot or cold spray. No need to stock two types of materials.

New Lower Cost

In evaluating any coating, always look at the cost per square foot, and the number of coats required to build proper film thickness. 33HB is nearly 24% cheaper per mil square foot than traditionally low cost 33...and compared to other leading vinyls, (see chart) savings are even greater. For example, although the gallon price of Coating "C" is 46% lower than 33HB, because of its low solids content the actual *material* cost for 5 mils thickness is almost 30% higher than 33HB, and the applied cost, (labor and material) is almost 90% higher.

For the full story, send coupon for data on 33HB and detailed cost comparison of the four coatings on the chart.

Amercoat® CORPORATION
4809 Firestone Blvd. · South Gate, Calif.

AMERCOAT Corp. Dept. GE
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Please send me full information on Amercoat 33HB

Name__________
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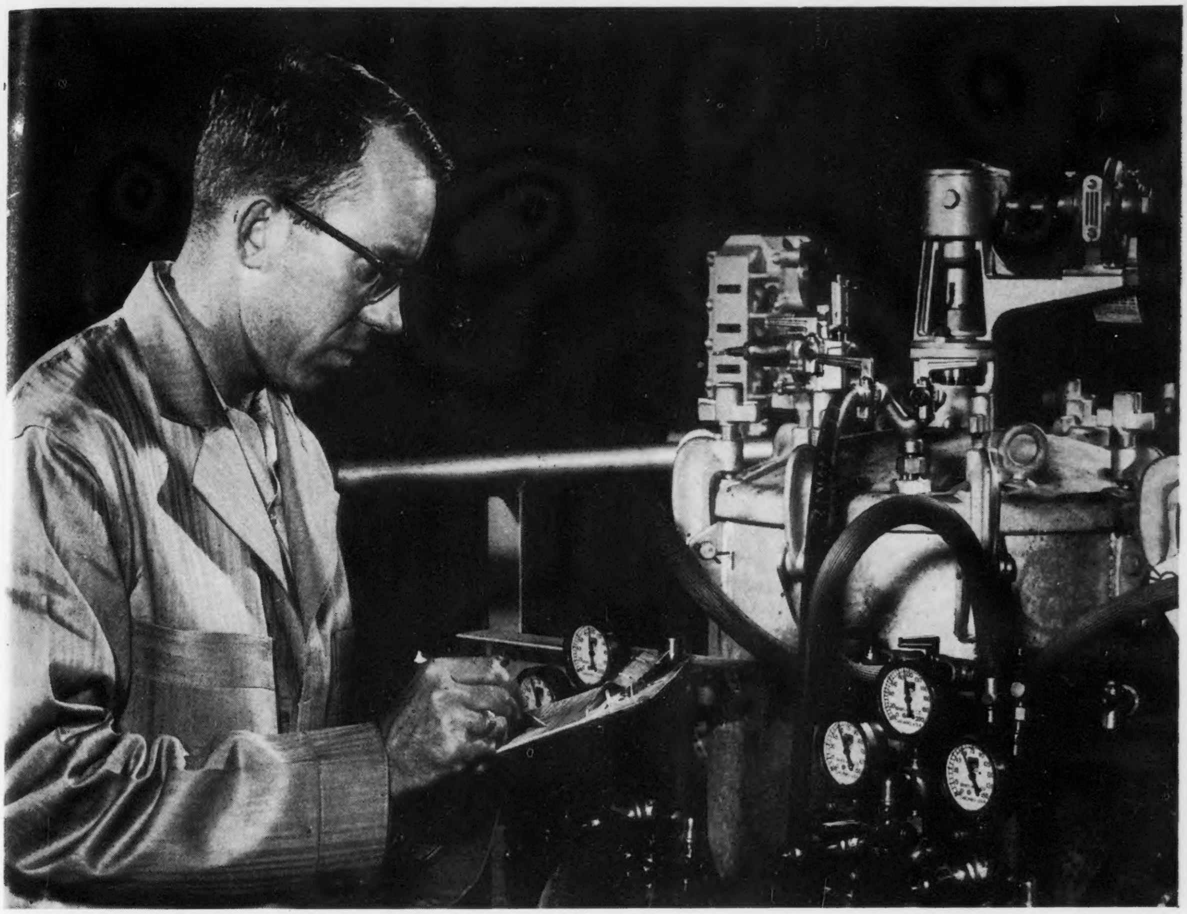
Th

th



The Search For Things To Come

T. L. C.
TRADE MARK

the proof of quality

In the search to develop new products and better processing techniques, TLC stands with the most progressive research-minded companies. In the Research Department at TLC, the standard question is, "How can we make the product better?" In the Laboratory, the answer is, "We can try this . . ." And the experiments continue. Out of the brain-storming quest for solutions to the problems of making a better product came the revolutionary automatic continuous baking oven — the *first major processing improvement* in 17 years in the lining of oil field tubing. Out of the laboratory, where the top research men in the plastic lining business are continuing their day-after-day search, has come the maroon TLC_4 — the hardest, toughest baked-on plastic lining yet developed. In the plant, product control checks are the responsibility of TLC's research men. Tests are made constantly in production to assure uniform high quality linings. Proven TLC_4 continues to undergo comparative tests to assure its constant superiority to other compounds used in the linings of oil field tubing. The result will be a better product, doing a better job . . . and will come from Tubular Lining Corporation.

TUBULAR LINING CORPORATION
LARRY E. HEINEN, PRESIDENT
JAckson 3-7013 • P. O. Box 20015 • Houston 25, Texas

These Galvomag anodes give us 25% more current than conventional magnesium anodes

Two questions should be asked by anyone who is planning to use galvanic anodes to protect well casings or other underground equipment:

(1) Which anode has the greatest throwing power? Galvomag® magnesium anodes deliver 25% higher current than conventional magnesium anodes—enough punch to assure adequate protection in high-resistivity soils.

(2) Which anode will do the job with the fewest units? Again, the answer is Galvomag. The extra current supplied by these high-potential anodes means four will do the job of five ordinary anodes in normal soils. Net result: lower installation and replacement costs.

Any of the Dow magnesium anode distributors listed below can give you more information. Contact the one nearest you or write directly to us. THE DOW CHEMICAL COMPANY, Midland, Michigan, Department MA 1429FF.

Call the distributor nearest you: **Cathodic Protection Service, Houston, Texas • Corrosion Services, Inc., Tulsa, Oklahoma • Electro Rust-Proofing Corp. (Service Division), Belleville, N. J. • Ets-Hokin & Galvan, San Francisco, Calif. • The Harco Corp., Cleveland, Ohio • Royston Laboratories, Inc., Blawnox, Penna. • Stuart Steel Protection Corp., Plainfield, N. J. • The Vanode Co., Pasadena, Calif.**

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Corrosion

devoted entirely to corrosion
research and control

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APEX for cathodic protection

MAGNESIUM ANODES

Corrosion control for under-ground and under-water pipelines and other metal structures regardless of all other methods used.

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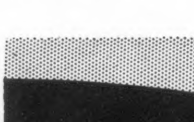

APEX Anodes are now available in 5 lb., 10 lb., 17 lb. and 32 lb. sizes. You may order bare anode with or without wire, or complete packaged anode with wire and backfill ready for installation.

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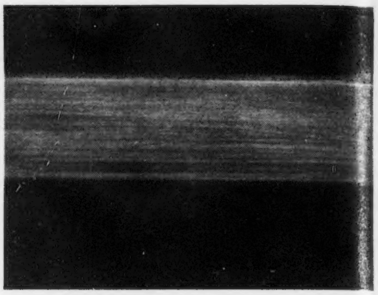

THIS MONTH'S COVER—Sparks are di charged from a holiday detector which inspec Polyken tape as it emerges from productio equipment. The multiple spark resulted whe an intentional holiday moved past the elec trode at less than normal speed. Inspectin 100% of the web for electrical discontinuitie assures better field results. See Page 123, News Section, for more information.

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Corrosion Is Indexed Regularly by Engineering Index.

Centrifugal Castings for Industry

Does your **Cylindrical** *problem call for a* **Centrifugal** *solution?*

If your product plans call for hollow cylindrical parts, give some thought to these facts. Manufacturers who had never seriously considered cast parts before are discovering important advantages in Sandusky centrifugal castings.

They're getting exceptional resistance to heat, corrosion, abrasion and stress, through the use of special alloys cast centrifugally . . . in diameters from 7" to 54", and lengths to 33 feet depending on diameter . . . and specially machined to specifications.

How can our versatile staff and facilities help you? Tell us your product requirements. Let us explore your ideas. Perhaps we can help solve your cylindrical problems through the vast foundry experience, metallurgical research and machining skills our 46 years offer.

Your request will bring more information promptly . . . or, if you prefer, a personal call by one of our engineers. Sandusky Foundry and Machine Company—Sandusky, Ohio.

Sandusky centrifugal castings offer you 4 important advantages:

1. ***SUPERIOR STRENGTH***—through non-directional mechanical properties
2. ***BETTER QUALITY***—machined castings are porosity-free
3. ***UNIFORM SOUNDNESS***—harmful inclusions are forced out by spinning motion
4. ***JOB-READY FINISHED CASTING***—reach you machined exactly to your specifications . . . eliminating extra costs from rejects, down-time, loss of production, etc.

See Our Booth #1339 at the Design Show

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• *T-2B-1 Sources of Impressed Current for Anodes*

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• *T-2B-2 Ground Bed Design Data*

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• *T-2B-5 Use of Platinum, Palladium, etc. for Anodes*

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• *T-2D-1 Short Insulated Sections of Low Conductance*

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• *T-2D-1 Inaccessible Locations, Such as Water Crossings*

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• *T-2D-3 Parallel Lines*

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• *T-2D-5 Pipe Observed to Be in a Stray Current Field*

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T-2E Internal Corrosion of Product Pipe Lines and Tanks

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T-2F Internal Corrosion of Crude Oil Pipe Lines and Tanks

(Election Being Held)

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• *T-2H-1 Methods to Classify Environmental Conditions*

(see chairman T-2H)

• *T-2H-2 Criteria for Reporting on and Evaluating Underground Coatings*

(see chairman T-2H)

• *T-2H-3 Specifications*

(see chairman T-2H)

• *T-2H-4 Internal Pipe Treatment Specifications*

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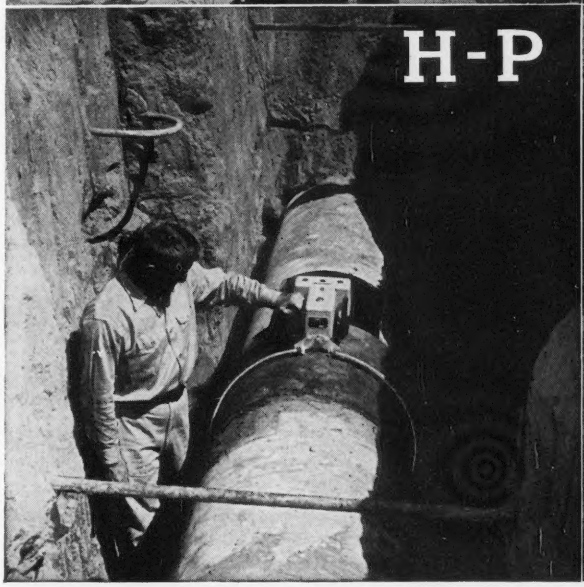

You Can't Patch It - If You Can't Find It!

These Electrical Detectors Show Up Weak Spots in Protective Coatings

E-4 Portable, pack-type, all-purpose, holiday detector with wet-cell battery output adjustable from 2500 to 20,000 volts D.C. Inspection electrodes for pipe sizes ¾ to 30-in. diam. also steel brush for surface checking. E-4 checks dry surfaces only.

E-P Holiday detector similar to E-4 but suitable for testing either wet or dry surfaces. The best general-purpose holiday detector made. Comes in sturdy carrying case with battery charger.

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M-1 Belt-mounted inspection instrument weighing but 3 lbs. Wand holds cellulose sponge which is dampened with plain water. When wiped over any painted or coated surface up to 10 mils thick it will signal pinholes or breaks by bell signal.

BEAT NATURE TO THE PUNCH

Your protective coatings on metal or concrete are only as good as their weakest points. Nature will seek out pin-holes and thin spots caused by air bubbles, dirt, coke or rust in the protective coating. Be safe and check pipe or other painted surfaces before putting them into severe service. A Tinker & Rasor electrical detector can quickly find the weak spot in your coating—wet or dry. It can do so rapidly and efficiently and without physical damage to the coating in any way. There is a T & R Holiday Detector for every surface testing job + each is fully guaranteed.

Write for data, costs, specifications. Inquiries receive prompt attention.

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(Continued from Page 6)

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- ***T-2K-1 Standards***

H. D. Segool, Chairman.

- ***T-2K-2 Research and Development***

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- ***T-2K-3 History and Results***

F. E. Costanzo, Chairman; Manufacturers Light & Heat Co., Pittsburgh, Pa.

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A. H. Roebuck, Chairman; Production Research Division, Continental Oil Co., Ponca City, Okla.

T-3A Corrosion Inhibitors

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L. C. Rowe, Vice Chairman; Research Staff, General Motors Corp., Box 188, North End Station, Detroit 2, Mich.

- ***T-3A-1 General Theory of the Action of Corrosion Inhibitors***

W. W. Sweet, Chairman; Research & Development Dept., Colgate Palmolive Co., 105 Hudson St. Jersey City, N. J.

- ***T-3A-2 Methods of Testing & Screening Corrosion Inhibitors***

(Chairman to be Selected)

- ***T-3A-3 Materials Available for and Application of Corrosion Inhibitors***

Lyle Timm, Chairman; Sharples Chemicals, Inc., Box 151, Wyandotte, Mich.

T-3B Corrosion Products

A. H. Roebuck, Chairman, Production Research Division, Continental Oil Company, Ponca City, Okla.

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T-3C Annual Losses Due to Corrosion

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T-3D Instruments for Measuring Corrosion

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- ***T-3D-1 Electrical Holiday Inspection of Coatings***

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T-3E Railroads

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- ***T-3E-1 Corrosion of Railroad Tank Cars***

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C. M. Jekot, Vice Chairman; DeSoto Paint & Varnish Co., P. O. Box 186, Garland, Texas.

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- ***T-3E-2 Corrosion in Railroad Hopper Cars***

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T-3F Corrosion by High Purity Water

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J. F. Eckel, Vice Chairman; Dept. of Metallurgical Engineering, Virginia Polytechnic Institute, Blackburg, Va.

- ***T-3F-1 Facilities for Production of High Purity Water***

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- ***T-3F-2 Inhibitors***

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- ***T-3F-3 Corrosion Products***

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- ***T-3F-4 General Corrosion Problems***

V. J. Payton, Chairman, Commonwealth Edison Co., 72 W. Adams St., Chicago, Ill.

- ***T-3F-5 Declassification***

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- ***T-3F-6 Intercommittee Activities***

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- ***T-3F-7 Bibliography***

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T-3G Cathodic Protection

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- ***T-3G-1 Cathodic Protection of Hull Bottoms of Ships***

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- ***T-3G-2 Cathodic Protection of Heat Exchangers***

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- ***T-3G-3 Cathodic Protection of Process Equipment***

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T-4A Effects of Electrical Grounding on Corrosion

T. R. Stilley, Chairman; Good-All Electric Mfg. Co., Good-All Bldg., Ogallala, Neb.

- ***T-4A-1 Recommendations for Materials to Be Used for Electrical Grounding to Reduce Corrosion***

(Appointment of chairman pending)

- ***T-4A-2 Recommendations for Grounding on Private Premises***

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T-4B Corrosion of Cable Sheaths

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- ***T-4B-1 Lead and Other Metallic Sheaths***

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- ***T-4B-2 Cathodic Protection***

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- ***T-4B-3 Tests and Surveys***

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T-4D Corrosion by Deicing Salts

D. W. Kaufmann, Chairman, International Salt Co., Inc., 638 Marine Trust Bldg., Buffalo, New York.

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- ***T-4D-1 Procedures for Conducting Field Tests Below Ground***

F. E. Kulman, Chairman, Consolidated Edison Co. of New York, Inc., 4 Irving Place, New York, N. Y.

- ***T-4D-2 Coordination of Field Programs Between Cities and Transportation Companies***

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T-4E Corrosion by Domestic Waters

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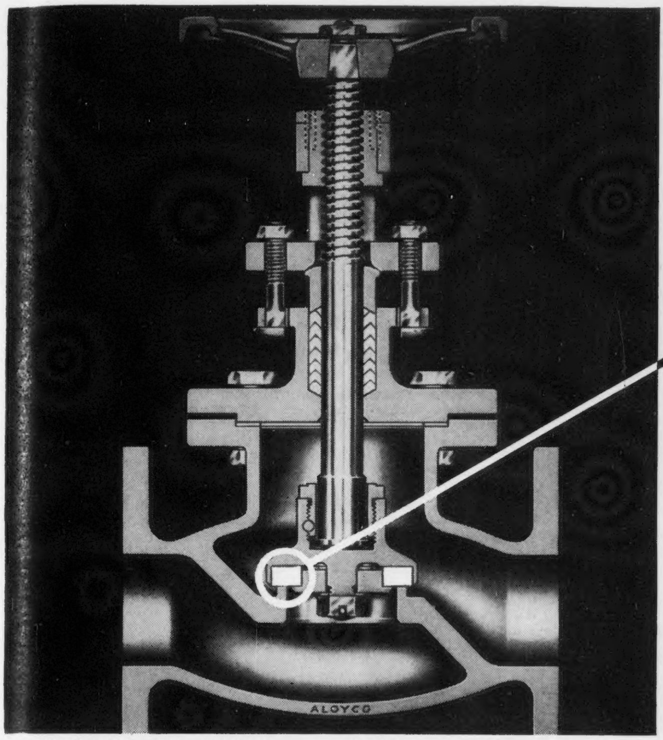
(Continued on Page 10)



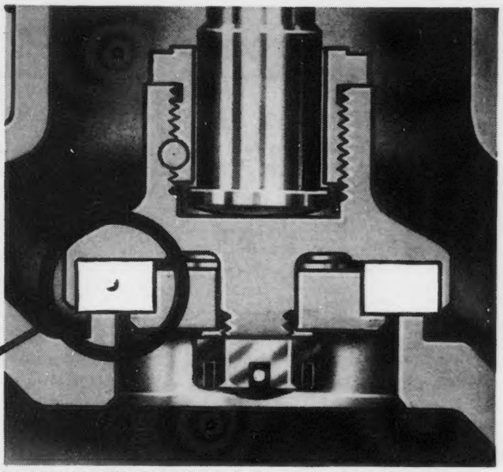
150 LB. ALOYCO GLOBE VALVE features bolted bonnet, and outside screw and yoke construction which keeps stem threads out of contact with corrosive fluids. Two piece gland plates and followers. Sound, heavy section body and bonnet castings. Stainless bolts. Heavy finished stem. Renewable yoke bushing. Flanged or screwed ends.

Tips on selecting valves to combat oxidizing solutions

High chromium and chromium-nickel stainless steels are the best alloys for these corrosive applications.

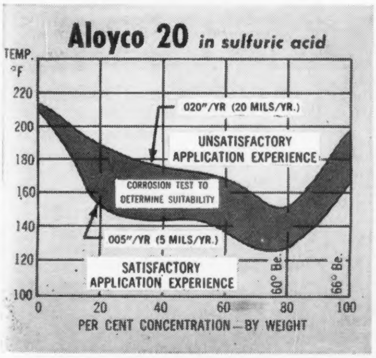
When exposed to oxidizing solutions they form protective films which restrain corrosive attack. Aloyco 18-8S, 18-8S mo and Aloyco 20 are good examples.

Valves should be constructed so that slight wear or corrosion won't require costly valve replacement. Renewable seats or discs shown above are one answer to this problem. So are deep stuffing boxes and outside screw and yoke construction. And, of course, all valve parts that come in contact with the corrosive fluid should be alloy steels. 6.18

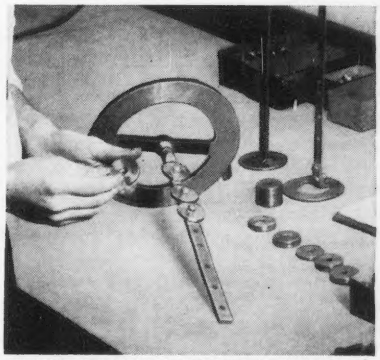


RENEWABLE TEFLON DISC is fully retained in disc holder so that even heavy overloads can't force it out of place. Machined seating surface assures wide full contact with disc and protects against distortion. Teflon V-type chevron packing rings are also used in deep stuffing box.

ALOYCO STAINLESS STEEL 18-8S (type 304) is expressly suited for resistance to oxidizing solutions. It also lends itself to innumerable other applications to prevent product contamination or discoloration. In Aloyco 18-8S mo (type 316), molybdenum is added to increase resistance to attack by pitting.



ALOYCO 20 provides a high order of corrosion resistance to a wide range of sulfuric acid concentrations at varied temperatures as indicated by the graph above.



ALOYCO TECHNICAL SERVICE includes engineering counsel, metallurgical assistance and field service. Samples are being prepared for plant line test above.

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FOR FURTHER INFORMATION on Aloyco corrosion-resistant valves, write to Alloy Steel Products Company, 1304 West Elizabeth Avenue, Linden, New Jersey.

Directory of NACE Technical Committees

(Continued from Page 8)

T-4F Materials Selection for Corrosion Mitigation in the Utility Industry

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• *T-4F-1 Materials Selection in the Water Industry*

Daniel Cushing, Chairman, 148 State St., Boston, Massachusetts.

• *T-4F-2 Materials Selection in the Electric Industry*

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Officers being Elected

• *T-5A-1 Sulfuric Acid*

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• *T-5B-5 Corrosion by Molten Salts and Metals*

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T-5C Corrosion by Cooling Waters

• *T-5C-1 Corrosion by Cooling Waters (South Central Region)*

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T-6 Protective Coatings

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T-6A Organic Coatings and Linings for Resistance to Chemical Corrosion

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J. I. Richardson, Secretary; Amercoat Corp., 4809 Firestone Blvd., South Gate, Cal.

• *T-6A-1 Heavy Linings*

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• *T-6A-5 Polyethylene*

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• *T-6A-9 Furanes*

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• *T-6A-13 Chlorinated Rubbers*

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• *T-6A-14 Organic-Brick Covered*

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• *T-6A-15 Rigid Vinyls*

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• *T-6A-17 Polyurethanes*

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• *T-6A-18 Hypalon*

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T-6B Protective Coatings for Resistance to Atmospheric Corrosion

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• *T-6B-1 Linseed and Other Drying Oils*

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• *T-6B-2 Ester Gum Oil*

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• *T-6B-3 Straight Phenolic Oil Varnish*

John W. Nee, Chairman, Briner Paint Mfg. Co., 3713 Agnes St., Corpus Christi, Texas

• *T-6B-4 Modified Phenolic Oil Varnish*

John W. Nee, Chairman

• *T-6B-5 Straight Alkyd Varnish*

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• *T-6B-6 Modified Alkyd Varnish*

G. G. Sward, Chairman

• *T-6B-7 Epoxy Esters*

Fred McDougal, Chairman, Shell Oil Co., Box 193, New Orleans, La.

(Continued on Page 12)

Holiday Detection is an important step in checking a coating job before it goes below ground. But it's *after* the line is laid that the real test of how well the coating material will withstand the attack of water and soil chemicals begins. That's why coal-tar enamel is used on most important pipelines: it has proved its ability to provide long-term protection of pipeline investment.

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CUT CORROSION LOSSES

a report by Koppers Company, Inc.

Number 10 of a series

Dr. W. F. Fair, Jr.
Corrosion Consultant

Since the security of a multi-million dollar investment is at stake, preventing corrosion in buried steel pipelines is extremely important. In this field the decisions made as to corrosion-prevention practice in the *design* phase are irrevocable—and can prove tremendously expensive if wrong.

* * *

Hot applied coal tar enamels have been traditionally the primary part of the protection system on pipelines. In recent years, cathodic protection has become widely accepted as a supplement to coatings. Enamels must now be judged as much on their value as long-term insulating materials as on their ability to prevent corrosion.

* * *

The best clue to a coating's performance is its ability to resist penetration by water. It is this inherent characteristic that determines a coating material's performance underground, with or without supplementary cathodic protection. As a coating absorbs water, it provides a decreased resistance to the flow of electric current between pipe and soil which is part of the corrosion process. Ultimately, water absorption leads to coating deterioration, which exposes bare pipe. In conjunction with cathodic protection, the coating system's most important function is that of a long-lasting electrical insulator so that impressed current requirements are kept to a minimum. Here too, a coating system's resistance to water penetration determines its performance. Actual pipeline operating experience has shown that the cost differential between maintaining cathodic protection on well and poorly insulated lines can amount to hundreds of thousands of dollars yearly.

* * *

Independent laboratories and industrial researchers have expended considerable time and effort in determining water absorption rates of protective coatings. Long-term tests have demonstrated, without exception, that coal-tar enamels have the highest resistance to water absorption among protective coating materials commercially available today.

The key to a coating's ability to resist water absorption seems to depend on the inherent molecular structure of the base material. The relative performance of a number of coatings in these various tests indicates that coating impermeability depends upon *aromatic content.* Coal tar enamel binders with an aromatic content in excess of 90%, show excellent water resistance in all tests while less aromatic materials show comparably poorer performance. Materials high in paraffinic content have been shown to leach under extended immersion.

* * *

An audio-visual meeting presentation discussing this important subject in detail is available. If you are interested in having a group-showing of this material—which includes a sound film—please address your inquiries to "How Long Should A Pipeline Last?," Koppers Bldg., Pittsburgh 19, Pa. or to Koppers District Offices: Boston, Chicago, Los Angeles, New York, Pittsburgh and Woodward, Ala. In Canada: Koppers Products, Ltd., Toronto, Ontario, and Edmonton, Alberta.

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COATINGS AND ENAMELS

Directory of NACE Technical Committees

(Continued from Page 10)

• *T-6B-8 Epoxy (Amine Cured)*

Earl Gould, Chairman, Continental Oil Co., Harvey, La.

• *T-6B-9 Chlorinated Rubber*

Otto Grosz, Chairman, The California Co., Box 128, Harvey, La.

• *T-6B-10 Vinyls*

R. M. Robinson, Chairman, Continental Oil Co., Maritime Bldg., New Orleans, La.

• *T-6B-11 Metallic Silicates*

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• *T-6B-12 Coal Tar*

M. Mitchell, Chairman, Reilly Tar & Chem. Co., 1616 Merchants Bank Bldg., Indianapolis, Ind.

• *T-6B-13 Asphalt*

C. C. Allen, Chairman, Anderson-Pritchard Oil Co., 1000 Liberty Bank Bldg., Oklahoma City, Okla.

• *T-6B-14 New Developments*

Joe Rench, Chairman, Napko Corp., Box 14126, Houston, Tex.

T-6C Protective Coatings for Resistance to Marine Corrosion

Officers being Elected

T-6D Industrial Maintenance Painting

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R. S. Freeman, Vice Chairman, Cities Service Refining Corporation, Box 1562, Lake Charles, La.

• *T-6D-1 Economics of Maintenance Painting*

S. L. Lopata, Chairman, Carboline Co., 331 Thornton Ave., St. Louis, Mo.

• *T-6D-2 Standardization of Scope of Painting Specifications*

L. L. Sline, Chairman, Sline Industrial Painters, 2162 Gulf Terminal Dr., Houston, Tex.

• *T-6D-3 Paint Programs*

R. H. Bacon, Chairman, The Dow Chemical Co., Freeport, Tex.

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D. F. Dial, Jr., Vice-Chairman; The Pure Oil Co., Box 239, Houston, Texas

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A. R. Gabel, Vice-Chairman; The Dow Chemical Co., Midland, Mich.

J. H. Coghshall, Secretary; Pennsylvania Salt Mfg. Co., 3 Penn Center Plaza, Philadelphia, Pa.

• *T-6F-1 Curing*

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• *T-6F-2 Surface Preparation*

L. R. Mangram, Chairman; Linco, Inc., Houston, Texas.

• *T-6F-3 Inspection*

L. Barker, Chairman; Carbide and Carbon Chemicals Corp., South Charleston, W. Va.

• *T-6F-4 Safety*

(Chairman to be Announced)

• *T-6F-5 Application*

H. Foelsch, Chairman; A. Gusmer, Inc., Woodbridge, N. J.

T-6G Surface Preparation for Organic Coatings

Joseph Bigos, Temporary Chairman; United States Steel Corp., Applied Research Lab., Monroeville, Pa.

T-6H Glass Linings and Vitreous Enamels

T-6J Protective Coating Application Problems

T-6J Los Angeles Area, Protective Coating Application Problems

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W. M. Jakway, Secretary, Bechtel Corp., Box 58424, Los Angeles, Cal.

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• *T-6J-2 Application Procedure*

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• *T-6J-3 Inspection Techniques*

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• *T-6J-4 Cost Evaluation*

T. Doyle, Chairman, Furane Plastics, 4516 Brazil St., Los Angeles, Calif.

T-6K Corrosion Resistant Construction With Masonry and Allied Materials

L. R. Honnaker, Chairman; E. I. DuPont de Nemours Company, Inc., Eng. Dept., 13W15 Louviers Bldg., Wilmington, Del.

T-6R Protective Coatings Research

Joseph Bigos, Chairman, Applied Research Lab., U. S. Steel Corp., Monroeville, Penn.

J. H. Cogshall, Vice-Chairman, Pennsylvania Salt Mfg. Co., 3 Penn. Center Plaza, Philadelphia, Pa.

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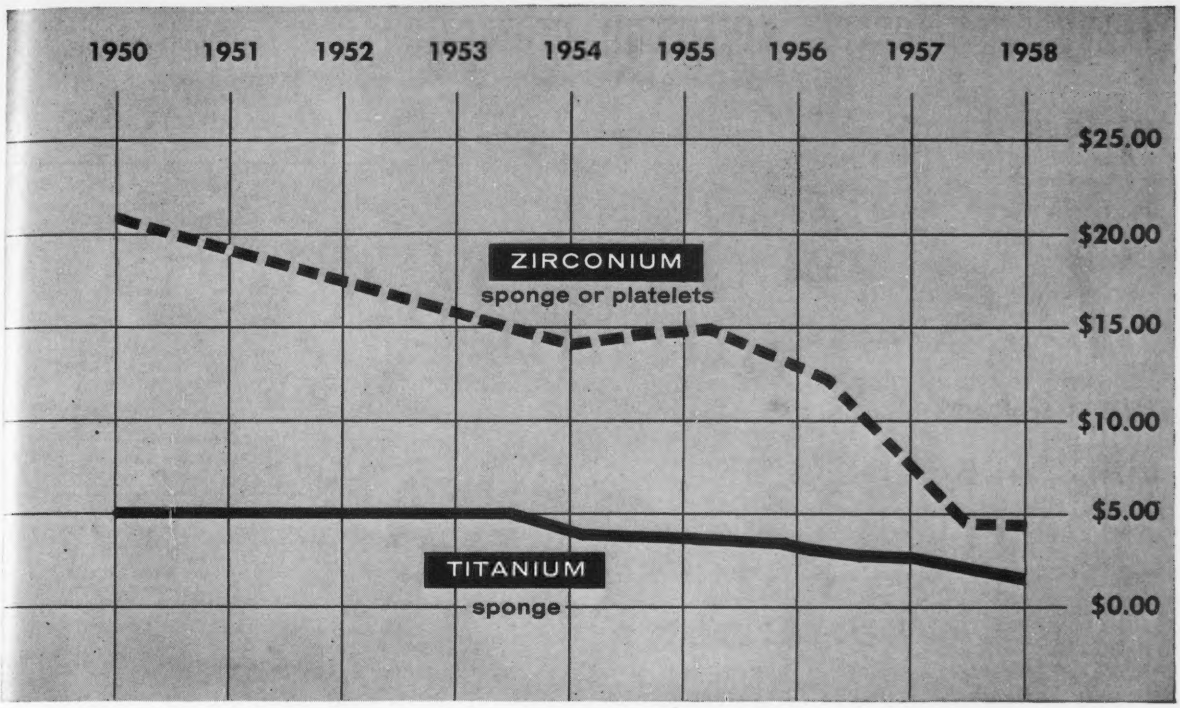

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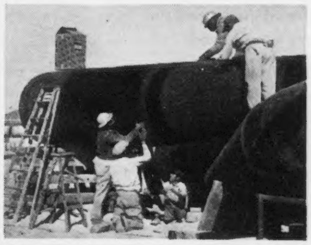

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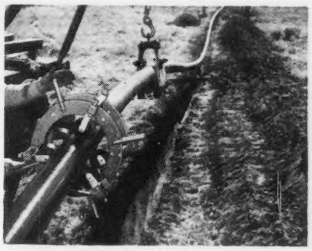

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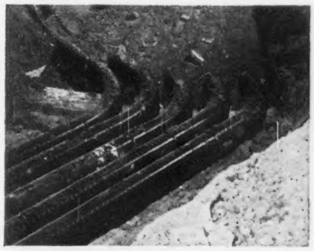

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Titanium Corrosion and Inhibition In Fuming Nitric Acid★

By H. B. BOMBERGER*

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Abstract

Evidence was found which indicates that sporadically rapid attack observed on titanium in red fuming nitric acid may, in some cases, be associated with a limited air supply in the test container. Additions of air, oxygen and certain salts resulted in noticeable corrosion inhibition. Attack in the uninhibited acid was found to be largely intergranular. In the case of a two-phase alloy the beta phase was removed preferentially, leaving a finely-divided pyrophoric deposit of the alpha structure. A possible mechanism is proposed for the observed breakdown in passivity. **1.2.5**

Introduction

TITANIUM IS well known for its high order of corrosion resistance to nitric acid and most other chemicals. This property of the metal, along with its high strength, low weight and increased availability aroused considerable interest in the use of titanium components for containing and handling highly concentrated nitric acid.

Both the red and white fuming acids are used as fuel oxidizers in rockets. In early tests carried out by different laboratories, excellent corrosion resistance was reported for titanium in both types of acid. The corrosion rates were usually about 0.1 mpy.[1,2] However, in more recent work exceptionally high rates of attack were observed in the red acid. In these cases the rate of attack ranged from 10 to 100 mpy and frequently adherent but pyrophoric corrosion deposits formed. The corrosion product was found sensitive to heat, shock and an electric spark, and in two cases it exploded with violence causing severe injuries to attending personnel. Most of the early work appearing in the open literature was reported by Ambrose and associates.[3] They suggested that the pyrophoric substance consisted of fine particles of titanium resulting from extensive intergranular corrosion. Their findings were later confirmed by other investigators.[4,5]

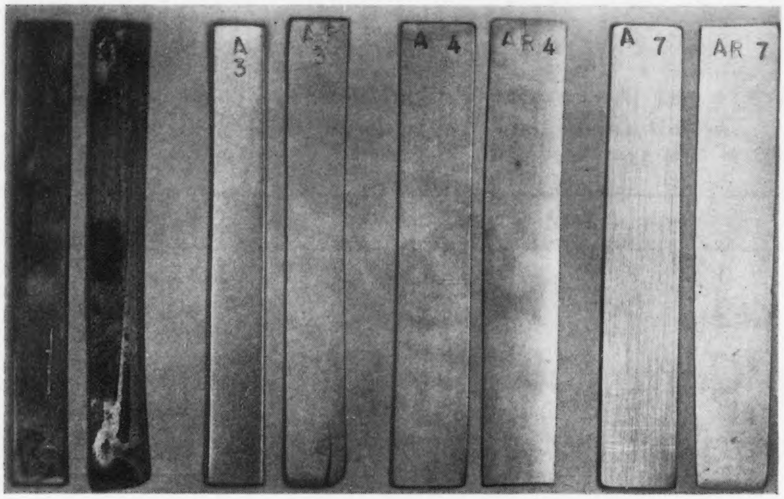
Larsen and associates[6] discussed a similar phenomenon that occurs on pickling uranium-zirconium alloys in nitric acid. Under certain conditions the matrix dissolves more rapidly than an intermetallic phase which, consequently, accumulates on the surface and then suddenly undergoes rapid oxidation with explosive violence. A solution to this problem was found by increasing the dissolution rate of the intermetallic phase by the addition of fluoride ions.

In the early studies there appeared to be no explanation for the sporadically slow and rapid corrosion of titanium in red fuming acid. At first the composition of the material was suspected as a cause inasmuch as alloys appeared to be more prone to this type of attack. The dissolved nitrogen dioxide appeared to play an important role in view of the fact that rapid attack was reported only in the red acid.

Rittenhouse and coworkers[4] reported considerable work on the effect of a number of variables and found that the pyrophoric tendency increases with increasing NO_2 content but decreases by increasing the water up to about 0.7 percent above which no sensitivity was observed.

★ Submitted for publication January 22, 1957.

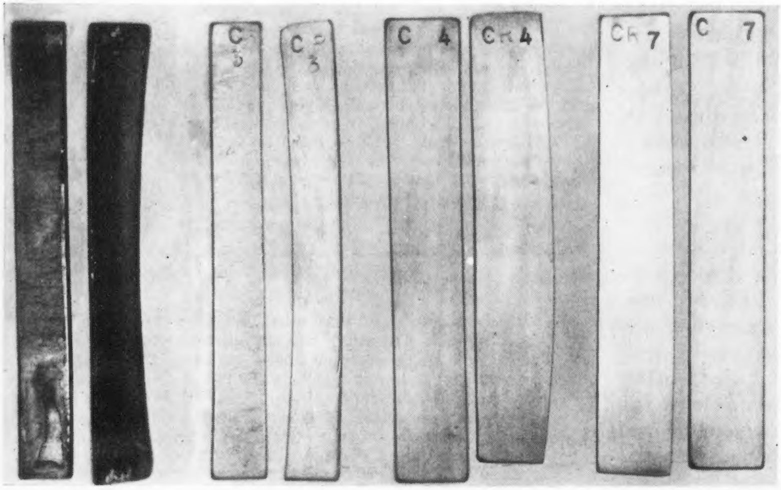
* Supervisor, Fundamental Research, Rem-Cru Titanium, Inc., Midland, Pennsylvania.



A CR A CR A CR A CR

Sealed Container 7 Days — Open Container 7 Days — Oxygen Flush 28 Days — 0.15% $CuSO_4$ Addition 28 Days

Figure 1—Samples of A70 in the annealed and cold rolled condition exposed to red fuming nitric acid. Note the heavy staining that occurred in the sealed containers and the absence of staining under the other conditions.



A CR A CR A CR CR A

Sealed Container 7 Days — Open Container 7 Days — Oxygen Flush 28 Days — 0.15% $CuSO_4$ Addition 28 Days

Figure 2—Samples of C110M in the annealed and cold rolled condition exposed to red fuming nitric acid. Samples show heavy staining resulting from a limited access to air and also show that air, oxygen and $CuSO_4$ prevented tarnishing.

In a more recent publication, Gilbert and Funk[5] reported this same trend and noted that an explosion had occurred in acid containing 1.34 percent water (with 24 percent NO_2) but not in acids with a higher water content. Since the Bureau of Mines explosion was reported to have occurred on testing titanium in a commercial grade of acid suspected of containing at least 1.5 to 2 percent water[7] it appears that a small amount of water by itself may not, in some cases, be an adequate inhibitor.

On reviewing the early data it seemed that rapid corrosion and subsequent pyrophoric reactions occurred only when titanium or titanium alloys were exposed to the red acid in *sealed* containers and, apparently, not in loosely covered containers. This suggested that inhibition may be affected by either oxygen or moisture pickup from the atmosphere, or both.

These possibilities were briefly investigated by a series of tests intentionally held to a minimum because of their hazardous nature and limited safety equipment. Although admittedly incomplete, the results are presented here in the hope that they may be of some interest to other investigators.

Experimental Procedure

Commercial titanium (A70) and Ti-7 percent Mn alloy (C110M) were tested in the annealed and 20 percent cold rolled conditions in fuming nitric acid, with and without special additions. The samples, about .050 inch x .5 inch x 4 inches were prepared by light pickling in 30 percent HNO_3—3 percent HF and washed in acetone. Four samples—one for each condition—were placed together in polyethylene flasks along with the solution. All but three of the tests were run in 550 ml flasks with 400 ml of solution. The three tests were run in 270 ml flasks with 270 ml of solution. For safety reasons glass equipment was not used. Two containers were left open to the air but all others were sealed by means of paraffin covers held down with two-pound weights. All tests were run at room temperature. At the conclusion of the tests the seals were removed and the acid flushed away by remote control. (An attempt to analyze the solutions, although technically desirable, was considered unwise with the available safety equipment.) The samples were dried and re-

TABLE 1—Composition of Materials Tested

MATERIAL	Tests in Which Used	C	N	Mn	Fe
A70	7 day	.16	.044	.10	.41
A70	28, 31 day	.07	.028	.20	..
C110M	7, 28 day	.07	.016	7.20	.21
C110M	31 day	.04	.02	7.30	.20

weighed, and the corrosion rates were determined in the usual way.

A commercial grade of red fuming acid was used, having a specific gravity of 1.59 to 1.60 gm/cc and a nominal composition of 20 percent NO_2, 78 percent HNO_3 and 2 percent water. The white acid consisted of 90 percent HNO_3 and 10 percent water and had a specific gravity of 1.49 to 1.50 gm/cc.

Two different heats of A70 and C110M were used. The composition of these materials is given in Table 1.

Experimental Results

In all tests the weight losses were quite small. However, as shown in Table 2, the rate of attack was considerably greater in sealed containers than in the open containers indicating that the air, moisture, or acid change affected the process. Presumably the rate of attack would have been still higher in tests 1 and 2, carried out in sealed flasks, had all the air in the vapor phase of 150 ml been replaced by acid. The samples in these sealed containers were the only ones which showed pyrophoric sensitivity on spark testing. In test 4 a smaller but open flask of 270 ml was used and filled to the top of its ½-inch diameter neck. This condition, with a smaller acid-air interface and thus more limited access to air, may explain the unexpected attack on the C110M.

Exposure of the anhydrous nitric acid to air undoubtedly resulted in some pickup of water, which apparently, also can cause some inhibition. (The water content of these acids was not determined because of inadequate safety equipment.) Test 5 was planned to determine if a small amount of water has an important effect. In this test significant weight losses occurred with the addition of 1.5 percent of distilled water, suggesting that the corrosion inhibition observed in other tests in the group may be associated with something other than, or in addition to, water. However, in this test there was no staining, stress corrosion or sign of pyrophoric tendency.

Tests 6 and 7 were carried out in sealed containers with one daily flush of commercial oxygen of about 500 ml through the vapor phase. But all weight losses were quite small and essentially no staining occurred. This indicated that in this case oxygen at least contributed to the inhibition.

Small additions of anhydrous $CuSO_4$ likewise were very effective. Essentially no staining, no cracking and very little weight loss occurred. CuCl additions, in which the Cu^+ was undoubtedly oxidized to Cu^{++} prevented staining but the sample of annealed C110M lost a significant amount of weight and many cracks developed in the cold rolled samples. The chlorine ion seems to be harmful under these conditions. An addition of metallic copper dissolved quickly, and was found to be effective in preventing staining but did not inhibit corrosion of the C110M or stress corrosion of the cold rolled material. From these limited data, metallic copper does not appear to be as satisfactory as $CuSO_4$. The reason for this may be that when the copper dissolves, the reaction yields reduction products of nitric acid that could have some effect.

A small amount of MnO_2 seemed to have no beneficial effect. Apparently, inhibition is complicated with additions of $FeCl_3$, as with CuCl, in which case the non-inhibiting chloride ions probably compete with the metallic ions for adsorption sites. Chromium salts are well known as inhibitors, but an addition of CrO_3 seemed to have little effect in the red acid. Likewise, NaBr did not seem to be beneficial in preventing corrosion and stress corrosion, contrary to an earlier report.[8]

Tests in the white acid, where the corrosion rates are ordinarily quite small, indicate that both oxygen and $CuSO_4$ additions helped to minimize staining.

The effect of restricted air, free access to air, and additions of oxygen and anhydrous $CuSO_4$ are shown in Figures 1 and 2 for both annealed and cold rolled A70 and C110M respectively, after exposure to the red acid.

All samples, except those sealed in the unaltered

TABLE 2—Tests in Fuming Nitric Acid

Number	Acid[1]	Addition[3]	Days of Test	CORROSION RATE IN MPY[4]				Staining Observed	Cracking Observed
				A70 Ann	A70 CR	C110M Ann	C110M CR		
1	Red	None	7	3.00	1.21	11.3	3.78	Heavy	Several small cracks on rolled edges
2	Red	None	28	1.82	1.80	3.04	3.00	Heavy	A few small cracks in CR A70
3	Red	Open to Air	7	0.07	0.09	0.09	0.09	None	One crack in CR A70
4	Red[2]	Open to Air	7	0.00	0.03	5.52	4.00	Slight	A few cracks in CR samples
5	Red	1.5% H_2O	28	7.43	7.15	11.2	10.7	Moderate	None
6	Red	O_2 Flush	28	0.06	0.03	0.02	0.20	Very slight	One crack in CR A70
7	Red	O_2 Flush	31	0.01	0.01	0.30	0.25	None	A few small cracks in CR C110M
8	Red	0.8% $CuSO_4$	28	0.01	0.00	0.00	0.01	None	None
9	Red	0.15% $CuSO_4$	31	0.03	0.02	1.95	0.24	None	None
10	Red	0.08% $CuSO_4$	31	0.01	0.02	0.05	0.09	Slight	None
11	Red	0.1% CuCl	31	0.03	0.04	5.5	0.37	None	Many cracks in CR samples
12	Red	0.06% Cu	31	0.02	0.02	0.31	0.79	None	Several cracks in CR samples
13	Red[2]	1% MnO_2	7	0.95	0.10	7.5	4.7	Slight	Several cracks in CR samples
14	Red[2]	1% $FeCl_3$	7	0.75	1.25	2.85	5.5	Slight	A few cracks on CR samples
15	Red	1% CrO_3	28	5.46	5.43	9.00	8.47	Slight	A few cracks on CR samples
16	Red	0.8% NaBr	28	0.53	0.41	1.32	1.20	Slight	Small crack in CR A70
17	White	None	31	0.02	0.02	0.02	0.02	Slight	No cracks, only C110M stained
18	White	O_2 Flush	31	0.01	0.02	0.04	0.01	Slight	None
19	White	0.15% $CuSO_4$	31	0.04	0.01	0.04	0.03	None	None
20	White	0.08% $CuSO_4$	31	0.04	0.03	0.00	0.02	None	None

[1] Acid volume was 400 ml in 570 ml flask except tests 4, 13 and 14.

[2] Acid volume was 270 ml in 270 ml flask.

[3] All containers sealed except 3 and 4 which were open to air.

[4] Materials tested in the annealed and 20% cold rolled conditions.

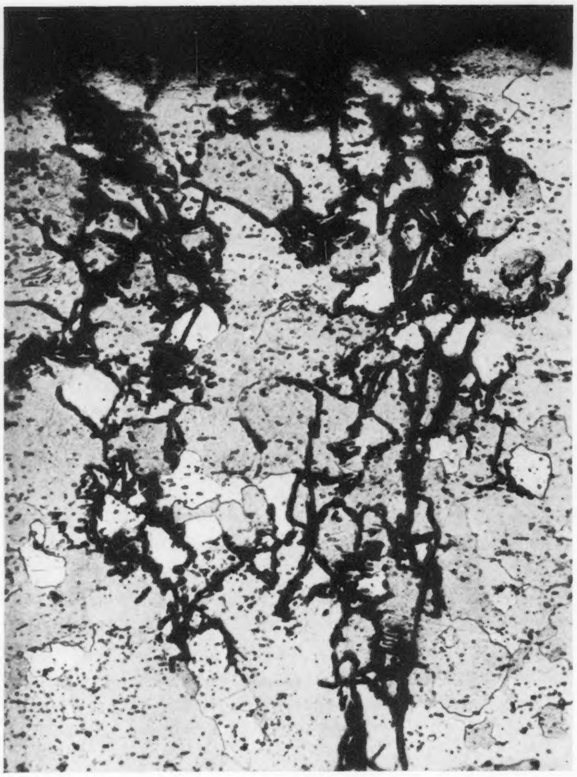


Figure 3—Photomicrograph of annealed A70 exposed to red fuming nitric acid in a sealed container for seven days. Note crack progression and porous nature of surface. 250X.

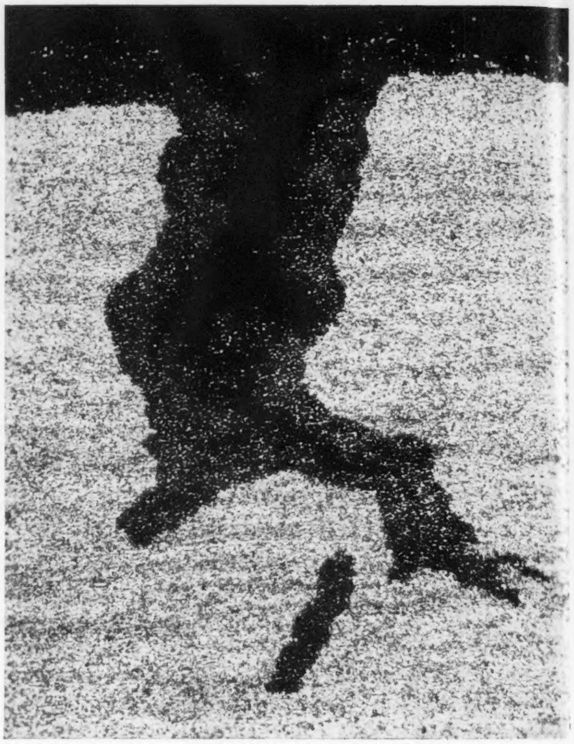


Figure 4—Photomicrograph of annealed C110M, also exposed to red fuming nitric acid in a sealed container for seven days. Picture shows nature of attack and selective leaching of the beta phase which resulted in a finely divided all-alpha deposit on the surface. 250X.

acid, showed very little staining or signs of general corrosion. However, all specimens sealed in the unaltered acid were heavily stained, and in some areas were porous and covered with a vitreous type of corrosion deposit.

Metallographic examination of the heavily stained pieces showed that the attack on A70 was essentially by intergranular corrosion yielding a rather porous surface as indicated by Figure 3. As shown in Figure 4, the action on C110M was similar. In this case, however, the attack resulted in preferential leaching of the beta phase from this two phase alloy leaving a finely divided metallic residue on the surface and in the crack. Analysis by a powder X-ray technique indicated that the residue was essentially all alpha titanium. This deposit was extremely sensitive and could be ignited by an electric spark.

Discussion

Although these data are not extensive, they nevertheless suggest that oxygen as well as other additions, such as $CuSO_4$, may contribute to the inhibition of titanium in red fuming nitric acid.

It may seem surprising that oxygen should have any effect on inhibiting corrosion of titanium in a powerful oxidizing agent such as fuming nitric acid. All oxidizing agents, even in small amounts, tend to passivate the metal.

The effect of HNO_3 additions to H_2SO_4 and HCl was reported by Golden, Lane and Acherman[3] as well as others. Schlain and Smatko[9] noted that dissolved oxygen and cupric ion ennobled titanium in dilute HCl. Uhlig and Geary[10] observed similar effects in dilute H_2SO_4. They pictured inhibition as resulting from a layer of oxygen, Cu^{++} or Fe^{+++} adsorbed on the surface. Inhibition of titanium in fuming nitric acid also might be explained in the same way.

It is certain that NO_2 has an important effect on the corrosion process since rapid attack has been reported only in the red acid. In the oxidation of titanium some reduction of the acid and probably NO_2 occurs even though the corrosion rate may be almost insignificant.

As long as a significant amount of oxygen is present, the reduction products, such as NO and HNO_2, should be oxidized back to NO_2 and HNO_3. Thus, one might speculate (but not conclude), that in a sealed container depletion of the oxygen could possibly occur and eventually the reduction products might compete with the metal for the adsorbed, passivating oxygen, causing a breakdown in passivity.

Summary

Rapid corrosion of titanium and the formation of a pyrophoric deposit was found to occur in red fuming nitric acid having no access to air. However, exposure of the solution to air or oxygen resulted in almost no corrosion. Additions of anhydrous cupric sulfate also resulted in markedly reduced attack, but an addition of 1.5 percent water caused somewhat increased corrosion rates but no sign of staining, cracking or pyrophoric tendency.

Under non-aerated conditions, extensive intergranular corrosion occurred in the unalloyed metal, and preferential attack of the beta phase took place in a two-phase alloy leaving a finely-divided pyrophoric all-alpha deposit.

Acknowledgments

The author is pleased to acknowledge the work of C. Petersen and J. Druzak for making the X-ray and metallographic studies and is indebted to M. B. Nordahl for a number of valuable suggestions.

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Any discussions of this article not published above will appear in the June, 1957 issue.

TECHNICAL PAPERS ON CORROSION WELCOMED

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The Corrosion Resistance of Ductile Iron In Sea Water and Petroleum Tanker Services★

By MICHEL PARIS and B. de la BRUNIERE

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Abstract

Laboratory data are given which compare the corrosion resistance of gray iron, steel and ductile iron in sea water and various acid solutions of different concentrations. Data also are presented to show the performance of ductile iron when used for product lines on petroleum tankers. Of particular interest is information presented for a low alloyed ductile iron which has given complete satisfaction under highly aggressive conditions in petroleum tanker service.

6.2.2

Introduction

DUCTILE CAST iron was introduced as an important member of the ferrous family of metals in 1948. This material (sometimes called nodular iron) has product advantages similar to steel and process advantages similar to gray cast iron. A comparison of certain properties of ductile iron with cast steel and cast iron is given in Figure 1.

Ductile iron is commonly produced by adding magnesium to liquid cast iron in sufficient quantities to cause the graphite to precipitate as spherulites rather than as flakes.

The purpose of this paper is to present the corrosion properties of ductile iron and to compare them with those of steel and gray cast iron. The data presented in this paper have been accumulated from (1) laboratory experiments carried out at the Pont-à-Mousson Research Center, Pont-à-Mousson, France, and (2) actual service data from pipe installed in tankers built or repaired in France. These data are based only upon experiments and service results obtained since 1950. For this reason considerably more time and corrosion testing are required before a complete story on the corrosion resistance of ductile iron can be presented.

All laboratory tests were made on samples taken from ductile cast iron and gray cast iron pipe made by the centrifugal cast DeLavaud process. Steel samples were taken from steel pipe and sheet steel. All laboratory samples were 40 mm x 40 mm x 5 mm (approximately 1.6 inches x 1.6 inches x 0.2 inch) and machined on all faces.

All actual service data on ductile cast iron were obtained from pipe commercially produced in the DeLavaud plants in France.

Three types of corrosion media are described in this paper:

1. Sea water
2. Chemical media
3. Petroleum media

Corrosion Tests in Sea Water

It is commonly accepted in Europe that gray cast iron has very good corrosion resistance in sea water. (See Table 1 for examples.) Its corrosion resistance is further improved if (1) the oxygen content of the sea water is low, and (2) the gray cast iron is submerged completely and not subjected to flow and ebb of tides. Applying this information, three series of tests were made. In these tests, the main purpose was to compare gray cast iron and ductile iron since a great amount of information on the corrosion rate of gray cast iron already had been accumulated. Steel was introduced to extend the scope of these experiments.

Tests were conducted as follows:

1. Samples were immersed in natural sea water. The water was mechanically stirred to introduce oxygen and the samples were located close to its surface. The results of this test are average values taken from ten separate experiments. The dispersion from all ten tests was low. The results are given in Table 2.
2. Samples were immersed in natural sea water,

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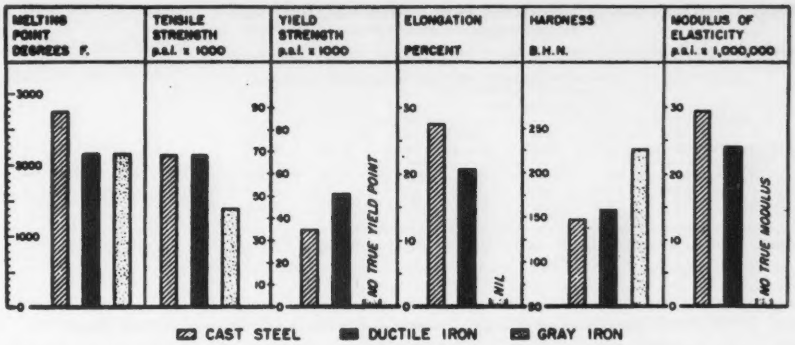

Figure 1—Six important properties of ductile iron as compared to those of cast steel and gray iron.

TABLE 1—Examples Showing the Durability of Cast Iron Pipe in Sea Water

Location		Year of Installation	Year of Inspection	Duration (Years)	Observations
Venice, Italy	Compagnia generale delle acque	1884	1952	68	Pipes were layed in the bottom of the lagoon. They were intact after 68 years.
Cannes, France	Ville de Cannes	1890 1901	1949 1949	59 48	The pipes are now in service in another location.
Beyrouth, Lebanon	Eaux de Beyrouth	1875	1953	78	The pipes are now in service in another location.
Calais, France	Ste Calaisienne des pates a papier	1906	1952	46	The pipes were intact.
Barcelona, Spain	Energica Electrica de Cataluna	1912	....	..	Pipes are still in service and in very good condition.
Boulogne, France	Cie Generale des Eaux	1884	....	..	Pipes were still in service in 1952.
Trouville, France	Ponts et Chaussees	1890	....	..	Pipes were still in service and in very good condition.
Antibes, France	Emissaires en mer	1902 1935	....	..	Pipes were still in service. Steel pipe layed in the same location was corroded after 12 years.
Nice, France	Emissaires de la baie des anges	1904	....	..	Pipes were still in service and in good condition. In 1934, a part of a new line made of 6% copper alloyed steel was layed at the same location. These pipes had to be replaced by iron 10 years later. See reference 7.

synthetic sea water and distilled water, all having air introduced continuously under pressure. Samples also were immersed in stagnant distilled water. Results of these tests are given in Table 3 and as in the previous test are average values for ten experiments.

3. Samples were exposed in sea water to accelerated cyclic phenomena similar to flow and ebb of tides. The total time required for each cycle is 20 minutes. Results of this test are given in Table 4.

These three series of tests indicate that ductile iron has a corrosion rate in sea water similar to gray cast iron, and in all these tests, a lower corrosion rate than steel.

Corrosion Tests in Chemical Media

Acid Media

Results of tests made in acid media are given in Tables 5-6. Data given there indicate that the corrosion rates of ductile iron in all acid media tested at 20 C are similar or less than those of gray cast iron. In sulfuric acid at 20 C and 100 C, the corrosion rates of ductile iron given in Table 5 are considerably less than those of steel.

Other tests indicate that ductile iron and gray cast iron have similar corrosion rates in picric acid and phosphoric acid.

Other Corrosive Media

Tests have indicated that the rates of corrosion of ductile iron and gray cast iron are similar in the following liquid media: sodium hydroxide, potassium hydroxide, copper sulfate and ammonia.

Corrosion Tests in Petroleum Tanker Service

One of the first applications for ductile iron pipe was for installations in petroleum tanker service. For this reason, considerable actual corrosion data have been obtained from pipe installed in tankers.

Three types of pipe are in service in tankers:

Filling pipe	(approximately 12 inches in diameter)
Discharge pipe	(approximately 6 inches in diameter)
Heating coils	(approximately 2-3 inches in diameter)

The heating coils are inserted in tanks and carry steam on the inside to heat the petroleum in the tanks to the proper temperature and the proper viscosity, for easy discharge.

In American built tankers, all the piping normally consists of steel. On those carrying sour crude from the Middle East the piping system must be replaced rather frequently (2 to 8 years) due to a very high rate of corrosion.

In European and French tankers built prior to 1950, all the piping normally consisted of gray cast iron. Because of the severe bending moments generated in tanker service at sea, it has been necessary to make gray cast iron pipe much thicker than standard pipe size and hence considerably heavier. Since gray cast iron has a very good resistance to corrosion, it normally lasts longer than the tanker itself.

It was hoped that ductile iron would be an ideal solution to tanker pipe corrosion problems. This material has mechanical properties similar to steel, thus not requiring heavy wall section, and its corrosion resistance was expected to be similar to gray cast iron. Actual service data obtained on ductile iron pipe installed since 1950 have indicated that the low alloy type of ductile iron (containing approxi-

TABLE 2—Comparison of Weight Losses of Ductile Iron, Gray Iron and Steel

	Loss of weight for various lengths of exposures					
	In mg/dm²/day			In ipy		
Material Tested	90 Days	180 Days	360 Days	90 Days	180 Days	360 Days
Ductile iron pipe....	24	16.1	13.2	.0048	.0032	.0026
Gray cast iron pipe..	24.9	16.4	14.5	.0050	.00325	.0029
Steel pipe..........	30.2	20.7	27.3	.0055	.0038	.0051

Note: Samples were immersed in natural sea water and mechanically stirred.

TABLE 3—Comparison of Weight Losses of Ductile Iron, Gray Iron and Steel

	Loss of Weight After Exposure of 380 Days							
	In mg/dm²/Day				In IPY			
	Air Introduced Continuously under Pressure			Stagnant	Air Introduced Continuously under Pressure			Stagnant
Material Tested	Natural Sea Water	Synthetic* Sea Water	Distilled Water	Distilled Water	Natural Sea Water	Synthetic Sea Water	Distilled Water	Distilled Water
Ductile iron pipe containing approximately 1.5% nickel..	15.6	15.6	18.9	5.9	.0031	.0031	.0038	.0012
Ductile iron pipe............	15.3	15.8	19.1	6.1	.0030	.0032	.0038	.0012
Gray cast iron pipe..........	17	19.4	19.3	6.2	.0034	.0038	.0038	.0012
Low carbon steel plate........	23.5	25.4	24.5	7.5	.0043	.0047	.0045	.0014

* Composition of synthetic sea water:

NaCl	30 grams
$MgSO_4.7H_2O$	5 grams
$MgCl_2.6H_2O$	6 grams
$CaSO_4.2H_2O$	1.5 grams
$KHCO_3$	0.2 grams
Distilled water	1 liter

TABLE 4—Comparison of Weight Losses of Ductile Iron, Gray Iron and Steel

	Loss of weight for various lengths of exposure					
	In mg/dm²/day			In ipy		
Material Tested	3 Months	6 Months	12 Months	3 Months	6 Months	12 Months
Ductile iron pipe containing approximately 1.5% nickel	43.5	44.5	42.0	.0087	.0089	.0084
Ductile iron pipe....	44.5	43.9	43	.0089	.0092	.0086
Gray cast iron pipe..	45.5	43.7	43.0	.0091	.0087	.0086
Steel pipe..........	62.5	64.0	64.0	.0115	.0118	.0118
Low carbon steel plate............	82.5	69.2	67.0	.0152	.0118	.0124

Note: Samples were immersed in natural sea water cyclically rising and falling every 20 minutes.

mately 1.5 per cent nickel) provides the ideal answer to the tanker pipe corrosion problem. Most tankers built in France since 1950 have been equipped with ductile iron pipe.

Summary of the Corrosive Conditions on a Petroleum Tanker

The petroleum carried by French tankers comes from the Persian Gulf. This petroleum has a high content in corrosive materials, mainly sulfurous types (free sulfur, hydrogen sulfide, sulfates, etc. . . .). After the petroleum is unloaded, the tanks are given a thorough cleaning with 60 C (140 F) sea water under pressure. Tankers returning to the petroleum loading harbor must fill up some of their tanks with sea water ballast in order to reach a correct stability for ocean travel.

A typical cycle on a tanker is as follows:

Environment	Time
Sour crude petroleum..................	3 weeks
Air	2 days
Cleaning with 60 C sea water under pressure	
Sea water ballast.....................	3 weeks
Air	a few hours

In addition to the corrosive products in solution, the raw petroleum also will contain sediments in suspension which deposit on the horizontal parts of the tanks (e.g., horizontal pipe, floor beams, etc.).

When corrosion appears in tanks of petroleum tankers, it normally is located in the areas covered with sediments. These areas are located mainly on the upper third of the horizontal pipes (on their outside surface) as well as on any horizontal parts in the tank. In case of discharge pipe, the corrosion appears on the lower inside surface of the pipe. Corrosion appears intermittently and takes the shape of small conical pits having depths of one half their diameters.

It has been proved that the sediments are required for the development of corrosion; however, they do not give the complete explanation of the phenomenon. Neither sour crude without sediments nor sea water approaches this corrosion rate

It is assumed that a chemical reaction occurs between the active sulfur of the sediments (its concentration may be as high as 0.6 percent) and sea water ending in the formation of sulfuric acid. Apparently, oxygen is necessary in this reaction and may come either from a direct oxidation when the tanker is empty, or from an indirect oxidation possibly due to bacteria. This theory seems to be confirmed by the fact the water taken from the pits contains sulfuric material and is acidic. In fact in one big pit, the water pH was as low as 3.5.

Summary of Laboratory Experiments

Pont-à-Mousson's Research Center worked on different chemical compositions of ductile iron in order to arrive at the best composition to resist pitting corrosion. These laboratory experiments were made with samples as described previously (40 mm x 40 mm x 5 mm) and submitted to the tanker service cycle. In one series of tests, the cleaning with 60 C sea water under pressure was eliminated.

Two other series of tests were made simultaneously. In one series the cycle began with sea water while in the second series, the cycle began with petroleum. The second cycle beginning with petroleum proved to be much more corrosive, and hence these data are given.

Samples of the following materials were tested:

1. Three types of ductile iron pipe:
   a. Austenitic ductile iron with a high nickel content.
   b. Ductile iron containing approximately 1.5 percent nickel.
   c. Unalloyed ductile iron.

2. Gray cast iron pipe.
3. Carbon steel seamless pipe.
4. Carbon steel sheet.

The results of these tests are summarized in Table 7. This table cannot be used to determine the life of pipe on tankers. Experience proves that the corrosion rate in service is somewhat higher than in the laboratory test. The table gives, however, an interesting comparative rate of corrosion of the various material tested. These laboratory experiments and other similar tests have been of great help for a rapid determination of the most suitable materials to be tried on tankers.

TABLE 5—Comparative Corrosion Resistance of Ductile Iron, Gray Cast Iron and Steel in Various Concentrations of Sulfuric Acid

Material Tested	Loss of Weight in mg/cm²/hour in Sulfuric Acid at Various Temperatures							
	Percent Concentration of Sulfuric Acid at 20 C				Percent Concentration of Sulfuric Acid at 100 C			
	0.5	5	10	33	0.5	5	10	33
Ductile iron pipe containing approximately 1.5% nickel	2.1	4.8	10.8	9.5	109	290	....	385
Ductile iron pipe	2.7	6.3	12	9.4	127	308	415	620
Gray cast iron pipe	3.4	6.6	14.6	13.5	92	276	370	470
Steel plate	3.9	9.6	16.0	16.0	189	334	515	1250

TABLE 6—Comparison of Corrosion Rates of Ductile Iron, Cast Iron and Gray Iron in Various Acids

Material Tested	Loss of Weight in mg/cm²/Hour				
	At 20 C			At 100 C	
	50% Hydrochloric Acid	30% Nitric Acid	30% Acetic Acid	50% Hydrochloric Acid	30% Acetic Acid
Ductile iron pipe	13	229	0.7	750	34
Gray cast iron pipe	25	222	0.7	522	48

Summary of Field Service Data on Corrosion Resistance Of Ductile Iron Pipe in Tankers

Corrosion Resistance of Unalloyed Ductile Iron Pipe

Some pitting corrosion was evident in early examination after unalloyed ductile iron pipe was installed in French tankers. However, when the pipe was examined after three years, the corrosion rate decreased. After four years, the corrosion pitting of ductile iron pipe unalloyed appeared to be almost completely stopped. On approximately 10 percent of the pipe, the diameter of the pits increased but their number and depth remained constant. After five years service in tankers, the corrosion appeared to be stopped completely.

It is interesting to note that in some cases ductile iron was installed on old American tankers (T2) in replacement of steel piping which lasted only four to five years. After the same length of time and under the most severe corrosion conditions (crude petroleum from the Persian Gulf is highly corrosive), virtually all unalloyed ductile iron pipe installations was performing satisfactorily. Indications are that they still have numerous years of service before replacement will be required.

Corrosion Resistances of Ductile Iron Containing Approximately 1.5 Percent Nickel

As a result of the laboratory tests given in Table 7, ductile iron pipe containing 1.5 percent nickel was tested on some tankers. Two specific results of these tests are as follows:

1. About 20 ductile iron pipes were installed in a 6 inch pipe line. After 14 months of service, there was no trace of corrosion, pitting, or graphitization on these pipes. They were covered with a light superficial and even coat of rust.

   Gray cast iron and unalloyed ductile iron pipe simultaneously installed showed some graphitization and pitting. The deepest pit was 1.5 mm.

2. On three tankers three ductile iron heating coils containing approximately 1.5 percent nickel were installed in two tanks, totaling approximately 7 km. (2296 ft.) of pipe. These coils were 60 mm. (2.5 in.) in diameter and carried steam at a temperature of 150 C.

   These three heating coils have been in shipboard service 2, 3 and 4 years, respectively. They are absolutely intact and no trace of corrosion is evident.

   The inlet and outlet ends of the heating coils were made of steel and submitted to the same corrosive conditions as the heating coils of ductile iron. On two of the tankers, the steel pipe had to be removed. The steel pipe on the third tanker showed numerous, deep corrosion pits, and in some instances there was risk of its being perforated.

From these tests, it appears that the ductile iron containing approximately 1.5 percent nickel is a very satisfactory answer to sour crude service corrosion. This iron has an electrochemical potential close to that of steel and consequently there is little danger of setting up stray electrolytic current between the ductile iron and steel.

Today approximately 40 tankers, mostly French, are equipped with ductile iron pipe which is giving satisfactory service.

Conclusions

This paper indicates that the corrosion resistance of ductile cast iron is similar to that of gray cast iron in all the media investigated.

Laboratory and actual service tests have indicated that ductile iron pipe containing approximately 1.5 percent nickel is most satisfactory in tankers carrying crude petroleum from the Middle East. It is felt that this conclusion could be extended to less corrosive crudes. The author has no particular data in the case of clean petroleum products.

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TABLE 7—Comparative Corrosion Resistance of Ductile Iron, Gray Cast Iron and Steel Under Laboratory Conditions Duplicating Conditions in Tanker Service

	Loss of Weight for Various Duration Testing						Maximum Depth of Pits of Corrosion After One Year of Testing			
	In mg/dm²/Day			In ipy			In Millimeters		In Mils	
Material Tested	**94 Days**	**275 Days**	**365 Days**	**94 Days**	**275 Days**	**365 Days**	**With Cleaning**	**Without Cleaning**	**With Cleaning**	**Without Cleaning**
Ductile iron pipe—(approximately 1.5% nickel)	11.6	9.6	7.3	.0023	.0019	.0015	0.1	0	4	0
Ductile iron pipe with austenitic matrix (approximately 12% nickel)	3.3	2.8	2.1	.00065	.00055	.0004	0	0	0	0
Ductile iron pipe	11.8	11.2	9.1	.0024	.0022	.0018	0.3	0.2	12	8
Gray cast iron pipe	15	10.8	9.5	.0024	.0022	.0019	0.1	0.1	4	4
Steel seamless pipe	15	13	11	.0029	.0025	.0021	0.6	0.2	24	8
Steel plate	14.1	12	10.2	.0028	.0023	.0020	0.4	0.3	16	12

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DISCUSSION

Questions by W. S. Quimby, New York, New York:

1. Have you noticed any pitting inside vertical pipe in crude tanks? When using steel pipe we have noticed similar pitting not due to deposits.

2. Is it possible that when steel and ductile iron were used together, ductile iron was cathodic and therefore actually was protected by the steel?

Replies by Michel Paris and B. de la Bruniere:

1. We have not noticed any pitting inside or outside vertical ductile iron pipe in crude tanks. We have had, however, only a few opportunities to see the inside of vertical pipe on tankers.

2. When steel and ductile iron of the kind we use in tankers are in electrical contact, ductile iron is slightly cathodic. The electrolytic corrosion of the steel (or protection of the ductile iron) may be neglected compared with the chemical corrosion in crude oil and sea water. Some of the ductile iron pipe was fixed with steel clamps. These clamps showed very early pitting caused by chemical corrosion. No evidence of any electrical corrosion was found at the contact points between the pipe and the clamp.

Any discussion of this article not published above will appear in the June, 1957 issue.

Corrosion Studies in High Temperature Water By a Hydrogen Effusion Method*

By M. C. BLOOM, M. KRULFELD, W. A. FRASER and P. N. VLANNES

Abstract

A new method for the measurement of static corrosion rates in aqueous systems at elevated temperature and pressure is briefly described. Data obtained by application of the method to ferrous systems are presented. These data include: (1) the corrosion rate of low carbon steel in distilled water at 600 F, (2) the effect of raising the pH in such systems, (3) the effect of thermal shock and of temperature rise on the corrosion rate, and (4) the effect of heat treatment of the metal on the corrosion rate. Comparison is made between the corrosion rates of low carbon steel and stainless steel and some data are included on the effect of the wall thickness of low carbon steel specimens on the rate of hydrogen effusion resulting from corrosion at 600 F. **4.6.2**

Introduction

A SURVEY was made about three years ago of the available knowledge dealing with the reaction of metals with water at elevated temperature and pressure. The survey was made in connection with a critical evaluation of material suitable for use in aqueous heat exchangers for nuclear power plants.[1, 2, 3] It was found that there was a surprising lack of data regarding the rates of the simple reaction:

$$\text{Metal} + H_2O \rightarrow \text{Metal Oxide} + 2H \qquad (1)$$

In the case of ferrous alloys, there was evidence that an oxide film having the spinel structure of magnetite (Fe_3O_4) was formed under most conditions of boiler and heat exchanger operation, but reliable quantitative data regarding corrosion rates were meager.

A major reason for the dearth of data appeared to be the lack of an adequate technique for making the measurements. A considerable effort was put therefore into the development of a technique capable of supplying the needed data. The technique has been described and discussed in detail elsewhere.[4] In this paper, the technique will be outlined briefly and some data obtained by its use on ferrous systems will be presented.

The method is based on the fact that in a sealed metal container at elevated temperature, hydrogen evolved as a result of the corrosion reaction (1) will permeate the walls of the container at a comparatively rapid rate. Because of this it is possible to calculate corrosion rates from measurements of the rate of hydrogen effusion through the walls of sealed vessels which are being corroded by the water or the aqueous solutions which they contain. For the purpose of these measurements, the vessels of the metal under test are surrounded by an evacuated system of known volume, and the rate of hydrogen effusion is calculated from measurements of the rate of pressure rise in the evacuated system.

Two types of container have been used: thin tubing with welded ends, and thicker tubing or pipe with a cone-in-seat type of pressure closure. Containers of the first type, which have been used in most of the work to be described, were fabricated from annealed steel tubing 0.25 inch OD and 0.020 inch thick. The tubing was partially flattened and completely filled with the aqueous fluid to be used as the corroding medium. Sections of the tubing were then pinched off and spot welded at the ends to form sealed capsules (Figure 1).

In use, the capsule is placed in the apparatus shown schematically in Figure 2. It is suspended above the oven zone by manipulation of external magnets operating on the counterweights, while the system is evacuated by the vacuum pumps. The vacuum valve is then closed and the specimen allowed to drop into the oven. The specimen heats rapidly to temperature, the flattened tubing expanding to accommodate the increased hydrostatic pressure. In the case of the steel capsules considered in this paper, the hydrogen generated by the reaction:

$$3Fe + 4H_2O \rightarrow Fe_3O_4 + 4H_2 \qquad (2)$$

diffuses through the walls of the specimen and collects in the vacuum system, building up a pressure which is recorded by a Pirani gauge and associated apparatus. Corrections can be made for "blank rates," due to slow outgassing of the system, or similar very small sources of gas build-up other than corrosion, by raising the capsule out of the hot zone and keeping it at room temperature until the blank rate is determined. After this the capsule is lowered back into the hot zone for further corrosion rate measurement. The corrosion rate is calculated from the Pirani gauge record, corrected for blank rate.

Experimental Data

Corrosion Rates of Low Carbon Steel in Distilled Water

In the work done with this technique, low carbon steel tubing (ASTM-A-192), hydrogen annealed, flattened and filled with distilled water (air-saturated), was subjected to corrosion at 600 F. The results are

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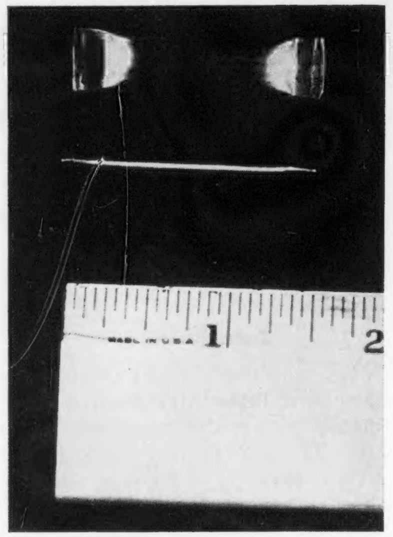

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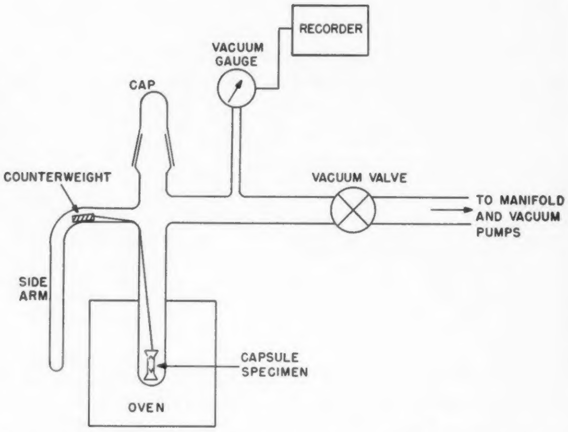

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A few runs were made to compare the relative corrosion resistance of low carbon steel and stainless steel (Type 347) under these conditions. The results are shown in Figure 3. It may be noted that even with stainless steel a comparatively high initial corrosion rate is indicated. Values in the neighborhood of 2000 mg/dm²-month were recorded after one hour of corrosion.

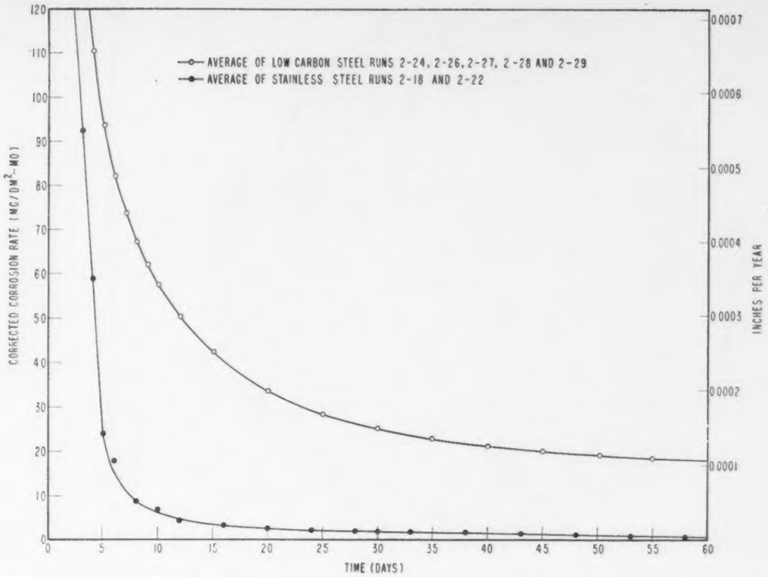

Figure 3—Corrosion rates of low carbon and stainless steel at 600 F in water raised to a pH (cold) of 10.6 with NaOH or NH_4OH.

The Effect of Heat Treatment on Low Carbon Steel Corrosion Rates

The very high corrosion rates indicated by the rapid hydrogen evolution noted in the early parts of the runs (see Table 1) could be in error if appreciable quantities of hydrogen had been left in the sample as a result of hydrogen annealing⁽¹⁾ operation. This hydrogen would be released rapidly when the specimen was dropped into the oven, and would indicate a spurious high corrosion rate. To eliminate this possible source of error, the hydrogen annealing operation was followed by a vacuum anneal⁽²⁾ prior to capsule fabrication. While this treatment did produce some reduction in the very high initial rates (from about 18,000 mg/dm²-month to about 13,000 mg/dm²-month) it produced another rather unexpected result. This unexpected development was an increase in the time needed for development of the protective film (see Table 4). Similar behavior has been noted by Douglas and Zyzes.[6] Chemical analysis and microscopic examination were used to determine whether chemical or structural changes might be responsible for this behavior. The chemical analysis (Table 5) and microscopic examination indicated no pronounced decarburization but the microscopic examination did reveal grain growth and carbide spheroidization as illustrated by Figures 4 and 5. There is evidence in the literature[7,8] that spheroidization tends to accelerate corrosion.

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3-6	H_2O	19,200	516	157	73	41	27	11	5	6	5
3-7	H_2O	14,400	575	197	104	56	34	13	9	7	7

TABLE 2—Corrosion Rate of Low Carbon Steel at 600 F

Sample		Corrected Corrosion Rate (mg/dm²-month)				
Run	Fluid	20 Days	50 Days	100 Days	150 Days	200 Days
3-6	H_2O	27	11	5	6	5
3-7	H_2O	34	13	9	7	7
2-28	NH_4OH[1]	41	23	10	7	7
2-29	NH_4OH[1]	45	24	9	7	7
2-24	NaOH[1]	32	19	11	..	..
2-26	NaOH[1]	21	13	5	7	5
2-27	NaOH[1]	28	17	7	6	7

[1] pH (Cold) = 10.6

TABLE 3—Corrosion Rate of Carbon Steel at 600 F in pH 10.6—11.0 (Cold) Aqueous Solutions

	Corrected Corrosion Rate (mg/dm²-month)						
	5 Days	10 Days	25 Days	50 Days	100 Days	150 Days	200 Days
Data of Blaser and Owens.....	85	51	24	13	8	6	5
H_2 Effusion Data	94	58	28	19	8	7	7

TABLE 4—Corrosion Rate of Carbon Steel at 600 F

Sample			Corrected Corrosion Rate (mg/dm²-month)				
Run	Fluid	Vacuum Annealed	20 Days	40 Days	80 Days	120 Days	200 Days
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(1) One hour in hydrogen at 1600 F followed by cooling in the hydrogen atmosphere to about 195 F in a water-cooled chamber.

(2) One hour minimum at 1600 F in a vacuum furnace maintained at a pressure of less than 10^{-5} mm of mercury, followed by furnace cooling to room temperature.

TABLE 7—Comparative Corrosion Resistance of Ductile Iron, Gray Cast Iron and Steel Under Laboratory Conditions Duplicating Conditions in Tanker Service

	Loss of Weight for Various Duration Testing						Maximum Depth of Pits of Corrosion After One Year of Testing			
	In mg/dm²/Day			In ipy			In Millimeters		In Mils	
Material Tested	94 Days	275 Days	365 Days	94 Days	275 Days	365 Days	With Cleaning	Without Cleaning	With Cleaning	Without Cleaning
Ductile iron pipe—(approximately 1.5% nickel)	11.6	9.6	7.3	.0023	.0019	.0015	0.1	0	4	0
Ductile iron pipe with austenitic matrix (approximately 12% nickel)	3.3	2.8	2.1	.00065	.00055	.0004	0	0	0	0
Ductile iron pipe	11.8	11.2	9.1	.0024	.0022	.0018	0.3	0.2	12	8
Gray cast iron pipe	15	10.8	9.5	.0024	.0022	.0019	0.1	0.1	4	4
Steel seamless pipe	15	13	11	.0029	.0025	.0021	0.6	0.2	24	8
Steel plate	14.1	12	10.2	.0028	.0023	.0020	0.4	0.3	16	12

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C. C. Reynolds, C. M. Adams, and H. F. Taylor. Prediction of Mechanical Properties from Chemical Composition for Fully Annealed Ductile Cast Iron. *Trans. of A.F.S.*, **61,** 510-515 (1953).

W. Glough. Flow and Fracture of Gray and Nodular Cast Iron. Sc. D. Thesis, Mechanical Engineering Department, M.I.T., 1954.

DISCUSSION

Questions by W. S. Quimby, New York, New York:

1. Have you noticed any pitting inside vertical pipe in crude tanks? When using steel pipe we have noticed similar pitting not due to deposits.

2. Is it possible that when steel and ductile iron were used together, ductile iron was cathodic and therefore actually was protected by the steel?

Replies by Michel Paris and B. de la Bruniere:

1. We have not noticed any pitting inside or outside vertical ductile iron pipe in crude tanks. We have had, however, only a few opportunities to see the inside of vertical pipe on tankers.

2. When steel and ductile iron of the kind we use in tankers are in electrical contact, ductile iron is slightly cathodic. The electrolytic corrosion of the steel (or protection of the ductile iron) may be neglected compared with the chemical corrosion in crude oil and sea water. Some of the ductile iron pipe was fixed with steel clamps. These clamps showed very early pitting caused by chemical corrosion. No evidence of any electrical corrosion was found at the contact points between the pipe and the clamp.

Any discussion of this article not published above will appear in the June, 1957 issue.

Corrosion Studies in High Temperature Water By a Hydrogen Effusion Method★

By ***M. C. BLOOM, M. KRULFELD, W. A. FRASER and P. N. VLANNES***

Abstract

A new method for the measurement of static corrosion rates in aqueous systems at elevated temperature and pressure is briefly described. Data obtained by application of the method to ferrous systems are presented. These data include: (1) the corrosion rate of low carbon steel in distilled water at 600 F, (2) the effect of raising the pH in such systems, (3) the effect of thermal shock and of temperature rise on the corrosion rate, and (4) the effect of heat treatment of the metal on the corrosion rate. Comparison is made between the corrosion rates of low carbon steel and stainless steel and some data are included on the effect of the wall thickness of low carbon steel specimens on the rate of hydrogen effusion resulting from corrosion at 600 F. **4.6.2**

Introduction

A SURVEY was made about three years ago of the available knowledge dealing with the reaction of metals with water at elevated temperature and pressure. The survey was made in connection with a critical evaluation of material suitable for use in aqueous heat exchangers for nuclear power plants.[1, 2, 3] It was found that there was a surprising lack of data regarding the rates of the simple reaction:

$$\text{Metal} + H_2O \rightarrow \text{Metal Oxide} + 2H \qquad (1)$$

In the case of ferrous alloys, there was evidence that an oxide film having the spinel structure of magnetite (Fe_3O_4) was formed under most conditions of boiler and heat exchanger operation, but reliable quantitative data regarding corrosion rates were meager.

A major reason for the dearth of data appeared to be the lack of an adequate technique for making the measurements. A considerable effort was put therefore into the development of a technique capable of supplying the needed data. The technique has been described and discussed in detail elsewhere.[4] In this paper, the technique will be outlined briefly and some data obtained by its use on ferrous systems will be presented.

The method is based on the fact that in a sealed metal container at elevated temperature, hydrogen evolved as a result of the corrosion reaction (1) will permeate the walls of the container at a comparatively rapid rate. Because of this it is possible to calculate corrosion rates from measurements of the rate of hydrogen effusion through the walls of sealed vessels which are being corroded by the water or the aqueous solutions which they contain. For the purpose of these measurements, the vessels of the metal under test are surrounded by an evacuated system of known volume, and the rate of hydrogen effusion is calculated from measurements of the rate of pressure rise in the evacuated system.

Two types of container have been used: thin tubing with welded ends, and thicker tubing or pipe with a cone-in-seat type of pressure closure. Containers of the first type, which have been used in most of the work to be described, were fabricated from annealed steel tubing 0.25 inch OD and 0.020 inch thick. The tubing was partially flattened and completely filled with the aqueous fluid to be used as the corroding medium. Sections of the tubing were then pinched off and spot welded at the ends to form sealed capsules (Figure 1).

In use, the capsule is placed in the apparatus shown schematically in Figure 2. It is suspended above the oven zone by manipulation of external magnets operating on the counterweights, while the system is evacuated by the vacuum pumps. The vacuum valve is then closed and the specimen allowed to drop into the oven. The specimen heats rapidly to temperature, the flattened tubing expanding to accommodate the increased hydrostatic pressure. In the case of the steel capsules considered in this paper, the hydrogen generated by the reaction:

$$3Fe + 4H_2O \rightarrow Fe_3O_4 + 4H_2 \qquad (2)$$

diffuses through the walls of the specimen and collects in the vacuum system, building up a pressure which is recorded by a Pirani gauge and associated apparatus. Corrections can be made for "blank rates," due to slow outgassing of the system, or similar very small sources of gas build-up other than corrosion, by raising the capsule out of the hot zone and keeping it at room temperature until the blank rate is determined. After this the capsule is lowered back into the hot zone for further corrosion rate measurement. The corrosion rate is calculated from the Pirani gauge record, corrected for blank rate.

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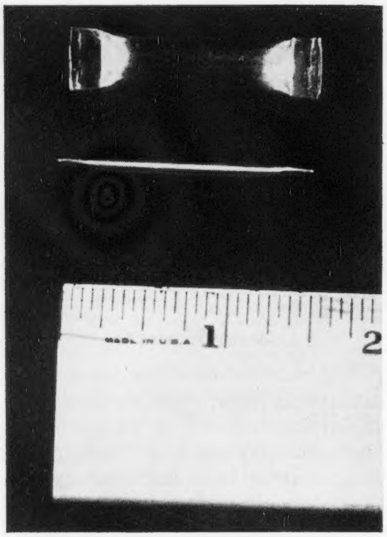
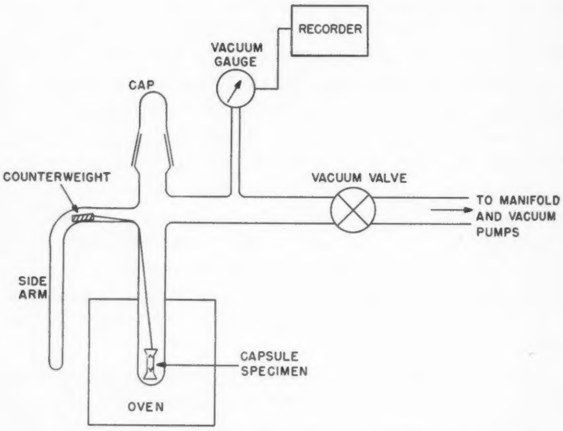


Figure 1—Sealed capsules for corrosion rate measurement.



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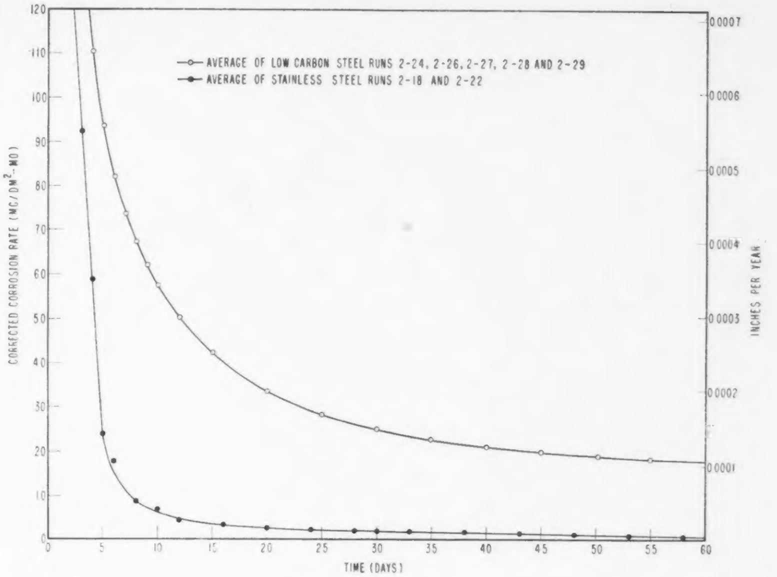

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⁽¹⁾ One hour in hydrogen at 1600 F followed by cooling in the hydrogen atmosphere to about 195 F in a water-cooled chamber.

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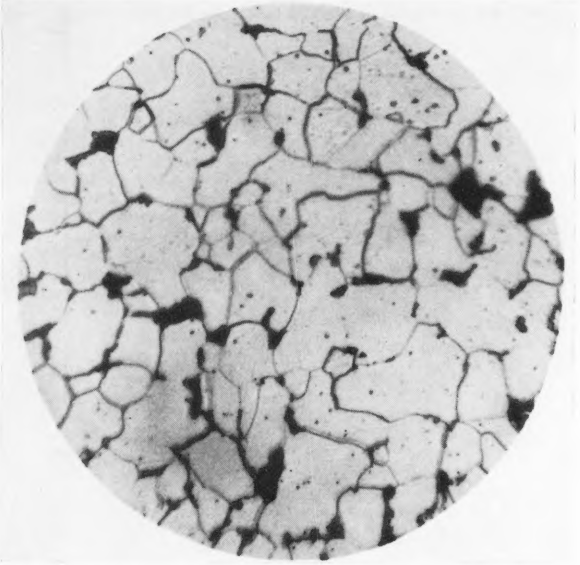

Figure 4—Low carbon steel after hydrogen annealing for one hour at 1600 F and cooling in the hydrogen atmosphere to 195 F in a water-jacketed chamber. Magnification 750X.

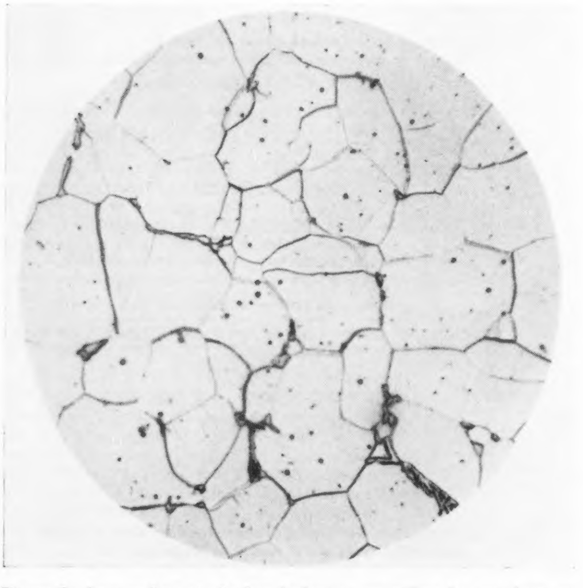

Figure 5—Low carbon steel after hydrogen annealing for one hour at 1600 F and cooling as in Figure 4, followed by vacuum annealing at 1600 F for one hour and furnace cooling. Magnification 750X.

Effect of Thermal Shock and of Temperature Elevation on Corrosion Rates

Figures 6, 7 and 8 show the effect of the thermal shock produced by raising the sample out of the oven, thus effecting a rapid cooling from 600 F to room temperature (75 F). It was anticipated that such thermal shocks and the accompanying mechanical shocks due to large changes in hydrostatic pressure might damage the protective oxide films with a consequent alteration of corrosion rates. The results, however, indicate that any damage that may thus be suffered is soon repaired. It may be noted that samples containing the NH_4OH solution show no appreciable effect due to the thermal shock (Runs 2-28 and 2-29). In those samples containing H_2O and the NaOH solution, an apparent rise in corrosion rate is observed immediately after return to high temperature and pressure but the rate soon returns to that in effect before the sample was removed from the oven (Runs 2-24, 2-26 and 2-27). The slower return of the samples containing water only may indicate a difference in the stability of the films formed in the two cases (Runs 3-6 and 3-7). It should be noted, however, that the longer period of film formation in the case of the NaOH solutions may have been a factor.

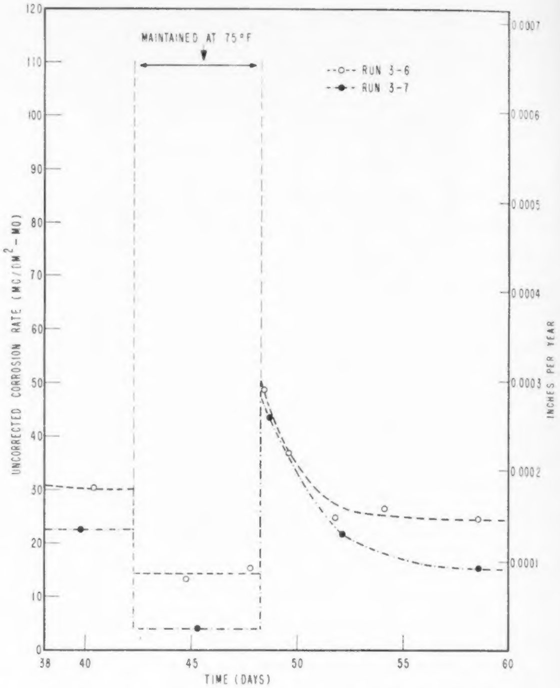

Figure 6—Corrosion rates of low carbon steel at 600 F in distilled water.

TABLE 5—Carbon Analysis of Tubing

SAMPLE	Percent Carbon in Duplicate Samples	
	Sample A	Sample B
Tubing as received	0.13	0.11
Hydrogen-annealed tubing	0.12	0.11
Hydrogen and vacuum-annealed tubing	0.11	0.11

Figures 7 and 8 also illustrate the effects of raising the temperature from 600 F to 650 F. The corrosion rate, as would be expected, immediately rises with the rise in temperature but it then drops at a much more rapid rate than had been the case at the lower temperature. Upon return to 600 F the rate returns to aproximately its previous 600 F rate or slightly less. The abrupt rise in corrosion rate at 650 F followed by a rapid decrease would seem to indicate that the protective film is being altered in a way which might eventually reduce the 650 F rate to the value found for the 600 F rate.

Dynamic Systems

The results obtained using the sealed capsules previously described give data on corrosion in systems without any flow of the fluid medium past the corroding metal surface. It is known that in dynamic systems the velocity of flow of fluid within piping and around the corroding metal components of such systems can have a considerable effect on the rate of corrosion.[5, 9] Dynamic systems were designed therefore in which vacuum-tight cans were welded around steel piping through which high temperature aqueous solutions could be circulated. Provisions were made for collecting the hydrogen effusing through the hot pipe wall into the cans and measuring and recording the pressure of such hydrogen as a function of corrosion time in a manner analogous to that employed with capsules.

In connection with this application of the hydrogen effusion method to the measurement of corrosion in piping some questions arose regarding the possible effect of wall thickness on the rate of hydrogen effusion. This was checked by fabricating capsules identical in all respects except wall thickness. The capsules were machined from a single length of low carbon steel rod. The inside dimensions of all capsules were the same but one set had a wall thickness of 0.028 inch and another a wall thickness of 0.153 inch, the latter being the thickness of piping in some of the dynamic systems mentioned above.

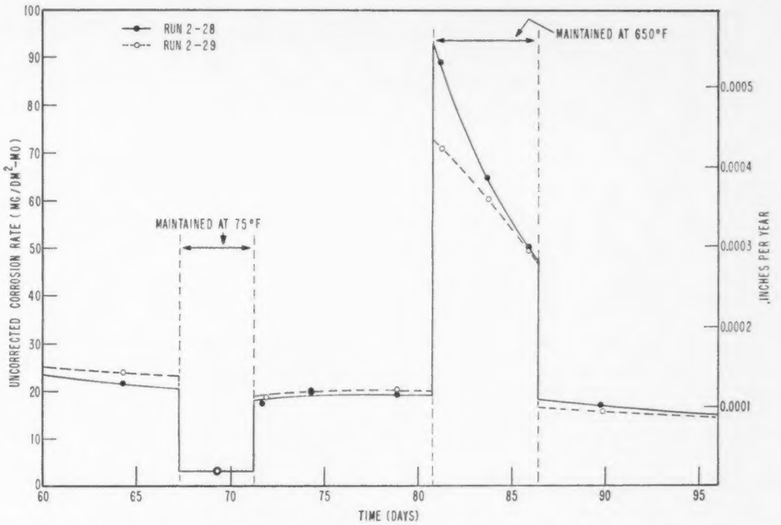

Figure 7—Corrosion rates of low carbon steel at 600 F in water raised to a pH (cold) of 10.6 with NH_4OH.

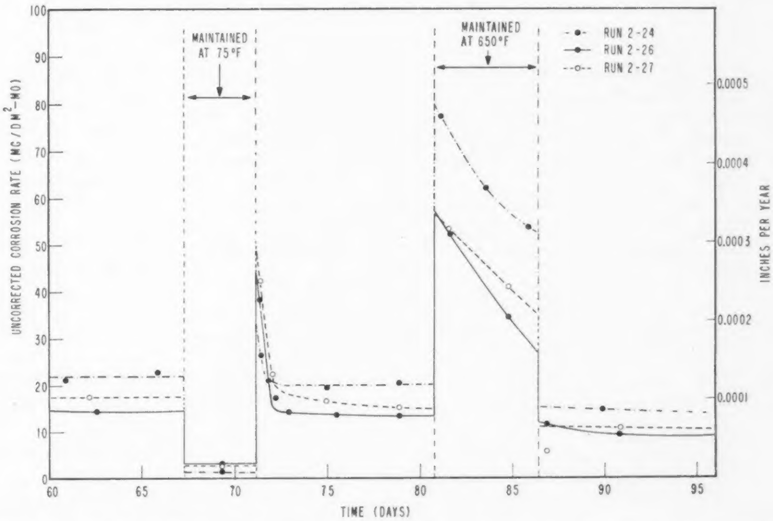

Figure 8—Corrosion rates of low carbon steel at 600 F in water raised to a pH (cold) of 10.6 with NaOH.

Closures were effected by seating a 59 degree cone into a 60 degree conical opening in the capsules. After hydrogen and vacuum annealing the capsule material, the capsules were filled with sufficient distilled and deionized air-saturated water to allow for expansion at 600 F without exerting hydrostatic pressure on the walls. The capsules were then sealed by means of the 59 degree cones and corrosion rate measurements made at 600 F.

The results obtained are shown in Figure 9. They are not as reproducible from specimen to specimen as those obtained with the thin-walled welded capsules, but reproducibility is sufficient to indicate that for low carbon steel a wall thickness of 0.153 inch compared to 0.028 inch does not appear to have any major effect on measurement of corrosion rates by hydrogen effusion at high temperature.

Some preliminary hydrogen effusion results have been obtained from dynamic systems by the hydrogen effusion method and it is hoped that significant results from this apparatus may be reported at a future date.

Acknowledgments

Thanks are due to G. N. Newport, I. M. Patterson and F. O. Westfall who assisted in the operation of the apparatus and made some of the measurements.

References

1. C. R. Breden, S. Greenberg, R. M. Robinson, A. H. Roebuck, V. F. Saitta, and C. C. Scott. Water Corrosion of

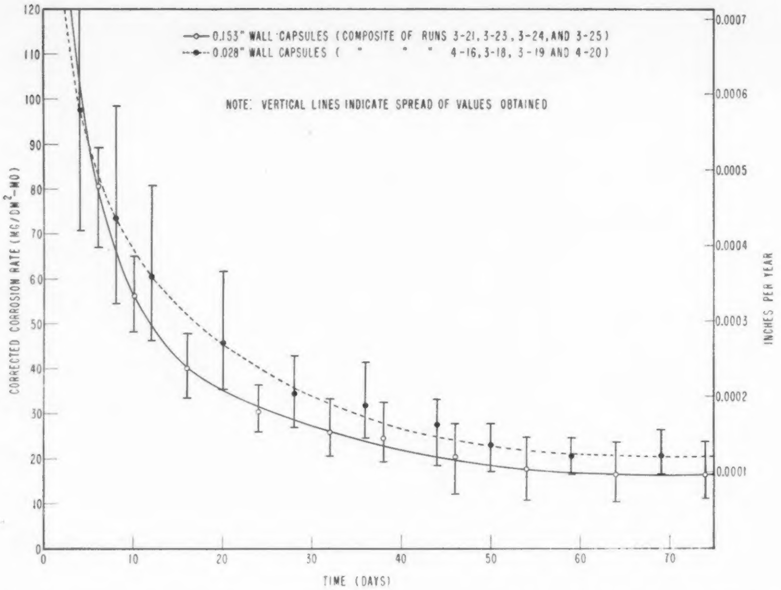

Figure 9—Effect of wall thickness on indicated corrosion rates of low carbon steel at 600 F in distilled deionized water.

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3. I. A. Rohrig, R. M. Van Duzer, Jr., and C. H. Fellows. *Trans. Am. Soc. Mech. Engrs.*, **66**:277-290 (1944).
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5. R. U. Blaser and J. J. Owens. Symposium on High-Purity Water Corrosion, ASTM Special Technical Publication No. 179, 1956.
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7. D. S. Kemsley. *Nature*, **175**:80 (1955).
8. R. W. Manuel. *Corrosion*, **3**:415 (1947).
9. H. R. Copson. *Ind. Eng. Chem.*, **44**: 1745-1752 (1952).

DISCUSSION

Question by J. E. Draley, Argonne National Laboratories, Lemont, Illinois:

Have you made any observations as to whether or not films on the outside of the capsules (corrosion product or otherwise) influenced the rate of hydrogen effusion?

Reply by W. A. Fraser:

No experiments have been carried out for the purpose of investigating this possibility. However, some of the capsules did develop blue oxide films on their outer surfaces during the experiments, probably due to small amounts of air leaking into the vacuum systems. No significant differences were observed between corrosion rates of the capsules having films and otherwise identical capsules without films on their outer surfaces, indicating that the films have no effect on hydrogen effusion rates.

Any discussion of this article not published above will appear in the June, 1957 issue.

Theoretical Studies and Laboratory Techniques In Sea Water Corrosion Testing Evaluation★

By F. L. LaQUE

FRANK L. LaQUE—Vice President and Manager of the Development and Research Division, The International Nickel Co., Inc., New York, Mr. LaQue has been prominent in the promotion of corrosion studies and the dissemination of corrosion-control data for many years. A past-president of NACE, he is a member of and has held responsible positions in many other technical organizations concerned with corrosion. He has been the recipient of many honors for his work in corrosion and has published numerous technical papers both in the United States and abroad.

Abstract

A number of laboratory tests can be used to advantage to determine the behavior of metals in sea water. Controlled tests are especially useful in appraising the merits of new or modified alloys and in screening a number of compositions by tests on small specimens so that large scale trials required for final evaluation can be restricted to those alloys that show the most promise in laboratory tests.

Sodium chloride solutions offer certain advantages in laboratory testing but results obtained in many cases are not the same as would be obtained in the more complex natural sea water. The composition of a satisfactory synthetic sea water solution is given. Data are given to show the correlation between corrosion rates of copper alloy specimens in natural sea water and in synthetic sea water. Results of comparative spray tests using natural sea water and synthetic sea water also are reported (for cold rolled steel and zinc.)

The apparatus used in making simple immersion tests is pictured. The effects of high velocity and turbulence are discussed in detail and results of such tests are reported for a number of metals. Results of jet impingement tests are also given.

The apparatus used in making corrosion fatigue tests of metal specimens exposed to sea water is described. Other topics discussed include crevice corrosion, galvanic potentials and polarization, and cavitation erosion. **2.3.1**

Introduction

MUCH HAS been learned about the behavior of metals in sea water through laboratory investigations. Such tests are particularly useful in studying the corrosion processes by which metals are attacked and the reasons for and extent of the superiority of one metal over another as it might be used in some practical application. Controlled tests are especially useful in appraising the merits of new or modified alloys and in screening a number of possible compositions by tests on small specimens so that the large scale trials required for final evaluation can be restricted to those alloys that show the most promise in the laboratory studies. This paper will describe the nature of some of these laboratory tests and will outline the advantages and disadvantages of each with some notes on precautions to be taken in planning tests and interpreting their results.

Composition of Testing Solution

Solutions of sodium chloride have been chosen frequently by students of corrosion as convenient environments in which to carry out studies of the nature of corrosion and corrosion processes. One of the attractive features of such chloride solutions is the ease with which they can be prepared to cover a broad range of salt concentration with its effects on electrical conductivity, oxygen solubility and the special activities of the chloride ion. There is, therefore, a great body of data on corrosion by solutions of sodium chloride. Unfortunately, however, there has been too much yielding to the natural temptation to assume that behavior in such pure sodium chloride solutions may provide a useful measure of performance in the much more complex natural sea water.

There also has been an inclination, on occasion, to justify the use of the simpler chloride solutions by the claim that thereby the research project has been given a fundamental character as compared with the "practical" studies undertaken with the natural sea water composition. In some cases, these so-called fundamental programs have been merely over-simplified studies in which the investigator evidently decided that the difficult to deal with complexities of sea water would be easier to ignore than to cope with.

Synthetic Sea Water

On the basis of the known composition of natural sea water as it varies from place to place in the oceans and seas, it is possible to prepare synthetic sea water solutions which are reasonably typical of what may be encountered. These synthetic sea water solutions vary from relatively simple mixtures of the principal constituents of natural sea water to quite complex solutions which include practically all of the compounds likely to be present. Probably the best of these solutions is the one first prepared by T. P. May and C. E. Black[1] at the U. S. Naval Research Laboratory and subsequently adopted by the American Society for Testing Materials under Designation D1141-52.[2]

For convenient reference, the composition of this synthetic sea water solution and instructions for its preparation are included here as Appendix A.

★Submitted for publication June 5, 1956. A paper presented at the University of California Corrosion and Fouling Conference, Scripps Institution of Oceanography, La Jolla, Calif., April 18-20, 1956.

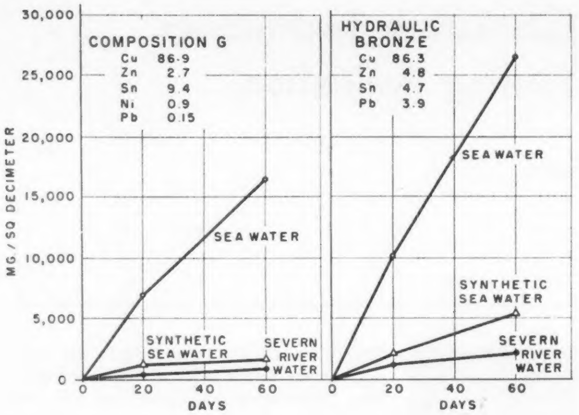

Figure 1—Corrosion test of flat bar specimens. Tip velocity was 28 feet per second.

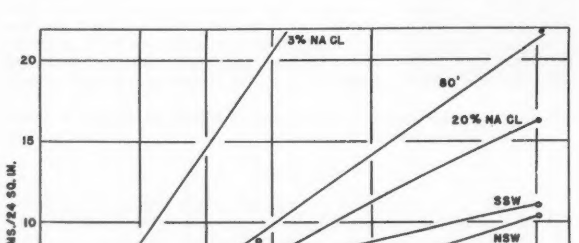

Figure 2—Comparative spray tests on cold rolled steel. Code to curves is as follows: 3% NaCl—spray tests in this brine; 20% NaCl—spray tests in this brine; 80'—exposure on test racks 80 feet from ocean; 800'—exposure on tests racks 800 feet from ocean; submerged—sea water immersion tests; SSW—salt spray tests in synthetic sea water; NSW—salt spray tests in natural sea water.

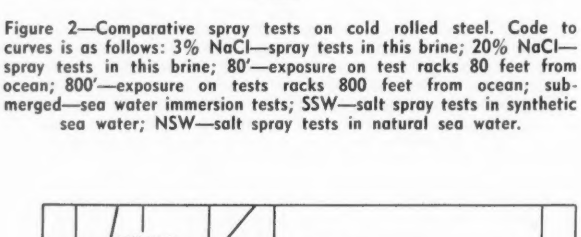

Figure 3—Comparative spray tests on zinc. Code to curves is as follows: 3% NaCl—spray tests in this brine; 20% NaCl—spray tests in this brine; 80'—exposure on test racks 80 feet from ocean; 800'—exposure on tests racks 800 feet from ocean; submerged—sea water immersion tests; SSW—salt spray tests in synthetic sea water; NSW—salt spray tests in natural sea water.

Comparisons of Tests with Synthetic and Natural Sea Water

Natural sea water is more than a chemical solution. It is a liquid world that is populated by many micro and macro-organisms, plants and animals that can have great effects on deterioration of metals by electrochemical, chemical, mechanical (abrasive) action plus combinations of these effects. Thus, tests made with even the most nearly complete duplication of the chemical composition of sea water or solutions of natural sea water salts often fail to yield results that will agree with those secured under otherwise similar testing conditions with sea water taken directly and immediately from the sea. This can be illustrated by tests of certain copper alloys carried out in a complex synthetic sea water in the U. S. Naval Engineering Experiment Station at Annapolis, Md. and in natural sea water at Kure Beach, N. C. The testing apparatus and the testing conditions, except for the corrosive medium, were identical and the specimens came from the same lots of material divided between the two test locations. Typical results[3] are shown in Figure 1.

Figure 1 shows that the natural sea water was much more aggressive than the synthetic solution or the brackish Severn River water. Of equal importance, was the fact that the relative performance of the several alloys tested was not the same in the different environments. Thus the use of the synthetic solution not only failed to disclose the possible intensity of the corrosive effect but also failed to indicate the proper order of merit of the alloys investigated.

Use of Synthetic Sea Water in Salt Spray Tests

Synthetic sea water acts more like natural sea water in tests designed to study resistance to sea spray or salt atmospheres (e.g., the common salt spray test.) This does not mean that a conventional salt spray test is a good way to study corrosion by the atmosphere—even a salt atmosphere. It means only that synthetic sea water corrodes metals in a salt spray box more like sea water does in a salt spray box than is the case with the straight sodium chloride solutions used in the standard salt spray tests as specified by the American Society for Testing Materials[4] by certain government bureaux and other writers of specifications who feel that results of the standard salt spray test or one employing an acidified solution[5] have a practical or scientific value greatly in excess of any recognized by the present author.[6]

Some illustrative data as reported by May and Alexander[7] have been reproduced in Figure 2 covering tests on steel and Figure 3 covering tests on zinc.

It will be seen, especially in the case of the tests with zinc, that spraying synthetic sea water (SSW) made up as described in Appendix A gave results in good agreement with those secured by spraying natural sea water (NSW).(1) It will be noted also that

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(1) Natural sea water cannot be sprayed through the nozzles used in standard salt spray boxes since it clogs them very quickly. It is necessary to eliminate suspended matter by passing the sea water through sand filters ahead of the spray nozzles.

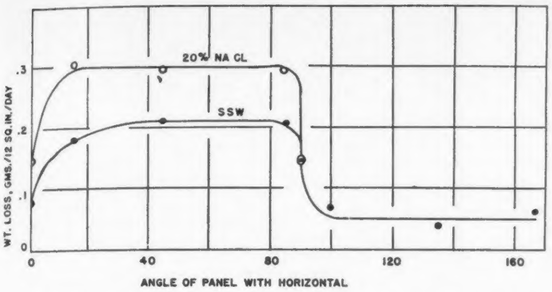

Figure 4—Corrosion rate versus specimen angle for cold rolled steel.

both the natural and synthetic sea waters were much less aggressive towards zinc than the simple sodium chloride solutions or exposure in or near the ocean (80 and 800 feet distant), that the more concentrated brine was more corrosive to zinc and that the dilute brine was more corrosive to steel.

Finally, both the natural and synthetic sea water sprays were less corrosive than natural exposure in a salt atmosphere close to the ocean in the case of steel and sea water as well in the case of zinc.

Preliminary studies in these investigations showed that since, in a salt spray box or chamber, the salt fog tends to settle vertically, the angle of exposure of test specimens can have a great effect on results, as shown by Figure 4.

To ensure maximum opportunity for attack and favor reproducibility of results, all flat specimens should be exposed at the same angle which should be from 30 to 70 degrees from the horizontal. Under such conditions corrosion will occur predominantly on the upward facing surfaces. The distribution of corrosion on specimens having a more complicated shape will be erratic—depending on the shapes and contours of the specimens.

Simple Immersion Tests

Laboratory studies involving natural sea water as the testing medium must be carried out with the same attention to external controlling factors as when any other corrosive medium is used. The most important of these factors are aeration (content of dissolved oxygen or other gases), temperature and velocity. A guide to the necessary control of these factors is provided by the American Society for Testing Materials Recommended Practices for Continuous Immersion[8] and Alternate Immersion Corrosion Tests.[9]

In simple immersion tests of the type considered here there is no interest in observing the peculiar erosive effects of sea water moving at high velocity. This will be dealt with separately. Control of velocity in simple immersion tests is generally for the purpose of securing reproducible velocity conditions. It should be kept in mind that difficulties are encountered in achieving zero velocity by reason of effects of vibration and of thermal convection currents and the agitating action of corrosion products as they stream over the surfaces below where they are formed. A simple device for achieving a moderate, uniformly distributed and reproducible velocity (e.g., about 15 feet per minute), is the vertical circular path apparatus first described by Fraser, Ackerman and Sands,[10] and later by Wesley.[11] This device is shown in Figure 5.

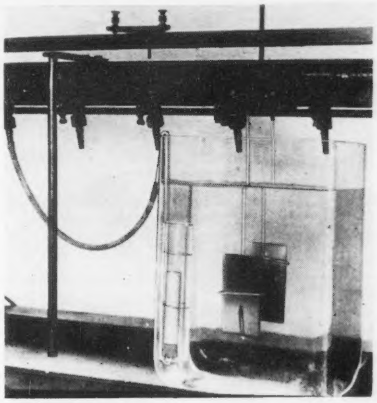

Figure 5—Vertical circular path test apparatus.

In view of the importance in corrosion of the minor constituents of natural sea water which are present in such low concentrations that they may become exhausted in the early stages of a corrosion test, the best practice is to locate the laboratory on the ocean. This is done so that a continuous supply of sea water can be passed through the test container by means of an appropriate feed and overflow arrangement. Otherwise, the sea water should be replaced as frequently as the available supply will permit.

When there is a plentiful supply of unpolluted water taken directly from the ocean its natural content of dissolved oxygen usually will be sufficient to accommodate the possible corrosion reactions. When the rate of renewal must be restricted because of limited supply or difficulties in temperature control it is possible to keep the dissolved oxygen content at the air saturation level by bubbling compressed air through sintered glass or alundum aerators, as shown in Figure 5. Other gases can be introduced in the same manner if desired.

The simplest way to control the temperature of the testing solution is to immerse the test container in a thermostatically controlled water or oil bath equipped with electric immersion heaters.

Deposit Attack or Crevice Corrosion

In practice, corrosion by sea water frequently occurs in an especially troublesome form in or around crevices. Such crevices may be associated with loosely attached marine organisms or other solid debris, within bearings, under packing, around shafts and valve stems and generally wherever there are closely fitted surfaces that are not sealed water-tight. To study resistance to such attack under controlled and reproducible conditions presents a difficult problem.

Some investigators create the desired corrosive conditions simply by placing a small pile of clean silica sand on the upper surface of an immersed horizontal specimen. By standardizing on the volume of the sand, the dimensions of the specimen and the area covered, it is possible to achieve a fair degree of reproducibility of the testing conditions.

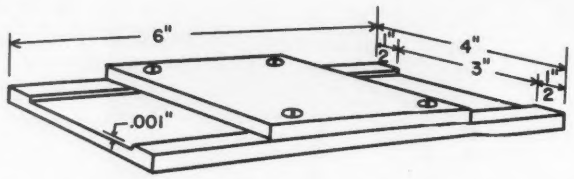

Figure 6—Arrangement used in determining the relationship between area effects and crevice corrosion.

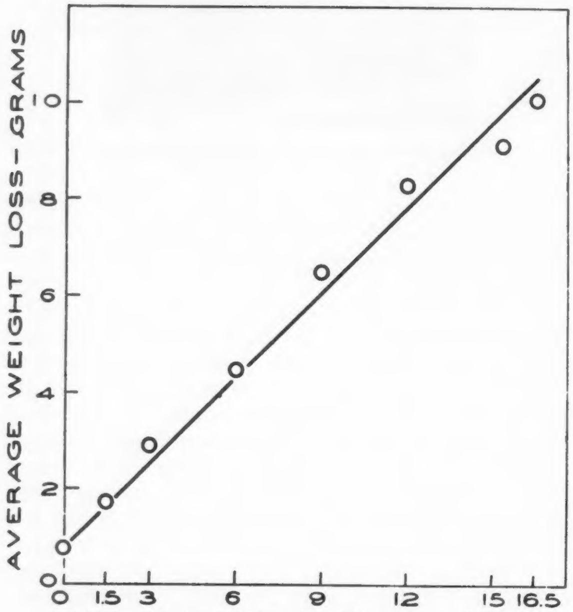

Figure 7—Relationship between area outside crevice and average weight loss.

Another means that has been used to create crevices has been simply to wrap an elastic band, string or wick around a specimen. This presents a difficulty, however, in reproducing the pressure and continuity of the contact from specimen to specimen.

Crevices can be formed by bolting one piece of metal to another metal or other material or to another piece of the same metal. The importance of area effects in studying crevice corrosion was illustrated by a series of tests[12] on a 17 percent chromium stainless steel in which the size of the piece that was attached to another piece of the same alloy was varied in a set-up illustrated by Figure 6. The total corrosion as measured both by weight loss and depth of attack that occurred in the anodic areas within the crevices was found to be dependent on the extent of the freely exposed cathodic areas outside the crevices, as shown by Figures 7 and 8.

Thus, once the dimensions of a test specimen and the relative areas within and without crevices have been established the extent of possible corrosion within the crevices will also be established and the results will be applicable only to situations where similar area relationships will exist.

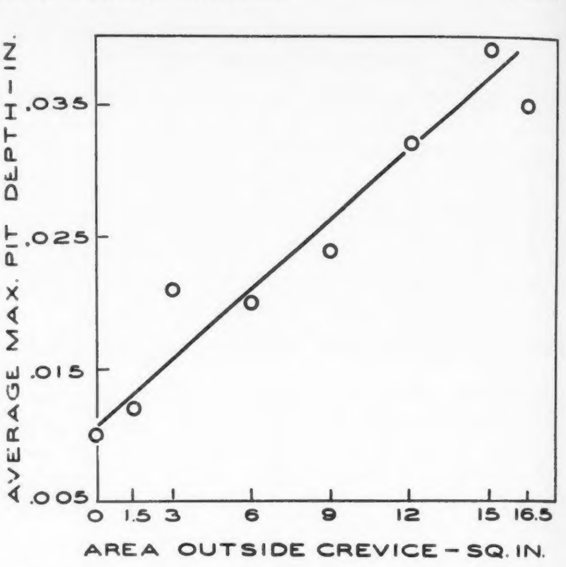

Figure 8—Relationship between area outside crevice and average maximum pit depth.

In many instances, and especially with materials that owe their resistance to corrosion to a condition of passivity supported by a free supply of oxygen or other oxidizing influences, corrosion may be confined to crevices while the freely exposed surfaces will remain free from attack. This occurs not only because of their greater accessibility to protective oxygen but also because of the electrochemical protection they will be given by the electrical currents flowing to them from the anodic areas within the crevices. When the test set-up is such that corrosion occurs in crevices (e.g., where the specimens rest or are held in place), no other corrosion may be observed and the effects that it is desired to study will be masked or overpowered by the results of crevice corrosion.

It is extremely difficult to avoid crevice corrosion of stainless steels in tests in sea water. Of the several greases, caulking compounds and the like that have been experimented with to seal crevices or otherwise avoid corrosion within them, ordinary zinc oxide ointment, as purchased in a drug store, has been found to be most effective and most reliable.

Effects of High Velocity and Turbulence

Many applications of metals in marine service require them to be able to withstand the erosive effects of sea water moving at high velocity. Such conditions are encountered by propellers, rudders, struts, ships' hulls, pump impellers, tubes in steam condensers and other heat exchangers, salt water piping, valves and so forth. It is necessary, therefore, to be able to evaluate resistance to such erosive effects and to study the mechanisms of damage under such circumstances.

The achievement of an exact and reproducible relative motion between a test specimen and a liquid is not easy. The problem is complicated by skin friction effects and by the tendency of a liquid to move with an object rotating within it or otherwise passing through it.

There are three principal ways of achieving velocity effects. One is to attach specimens to a disc

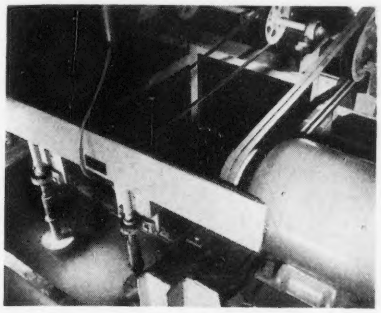

Figure 9—Apparatus used to spin test discs.

which can be whirled through the water in a vertical,[3] horizontal,[13] or inclined plane.[14] The specimens can be bars that project like the spokes of a ship's steering wheel beyond the periphery of a disc,[3] they can be attached like sections of tires to the rim of a relatively thick disc,[14] or they can be fastened to the surface of a disc at any appropriate radius. In any case, it is necessary to provide electrical insulation between specimens of different composition, or between a specimen and a metallic disc except in such cases as electrical connections may be made deliberately to observe galvanic or cathodic protection phenomena.

A second method is to move the specimen itself (e.g., by using a cylindrical specimen[15, 16] rotated around its vertical axis or a flat specimen in the form of a disc that can be whirled at any desired speed.[17])

Except in the case of specimens shaped to conform to the radius of the rim of a thick disc and the principal surfaces of a cylinder rotated around its vertical axis, all of these methods of exposure involve a velocity gradient over the surface of the specimen depending on the radius of rotation. Since, in many practical applications, similar opportunities for velocity gradients exist and certain mechanisms of damage are dependent on effects of differential velocities, this may be a desirable feature of a test method. It is achieved to a high degree in tests made by spinning a flat disc in a set-up such as shown in Figure 9. The appearances of some copper alloys after such a test are shown in Figure 10 and the quantitative results for these specimens in terms of loss of thickness as a function of apparent velocity in Figure 11.

There is a temptation to assign some absolute significance to the apparently critical velocities which mark the boundary between practically no attack and very considerable attack. Apart from questions as to the true relative velocity between the metal and the water, the locations of the attacked and unattacked zones and the rate of attack where it is most severe as related to apparent velocity are influenced by electrochemical action between the attacked and unattacked surfaces. This action may be the result of differences in potential between bare metal surfaces and those covered by adherent corrosion products or other films, or it may be the result of different rates of removal of soluble metal corrosion products so as to give rise to metallic ion concentration cell action. Since in such electrochemical cells effects of current density and electrical resistance are important, the dimensions of the test specimens are critical factors that will influence the results. Thus, the apparently critical velocity indicated by tests with one size disc will not be the same as that indicated by tests using a smaller or larger disc. This was illustrated by a series of tests with iron discs having different diameters but spun at the same number of revolutions per minute. The results are shown by Figures 12 and 13.

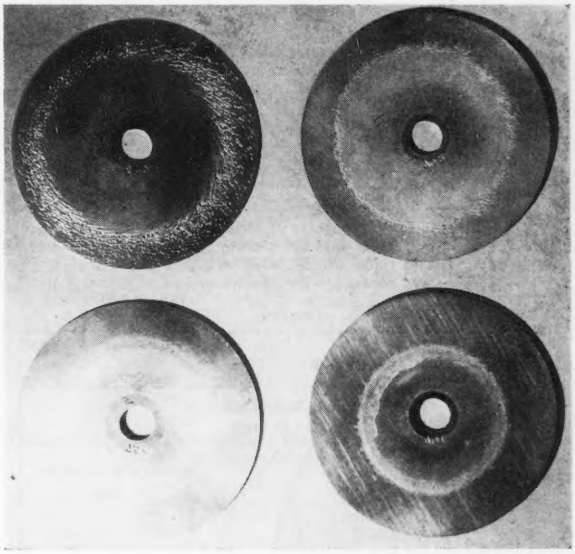

Figure 10—Appearance of discs after testing. Composition of discs is as follows: Upper left, Admiralty brass; upper right, high iron 70-30 cupro-nickel; lower left, high iron 90-10 cupro-nickel; lower right, low iron 70-30 cupro-nickel.

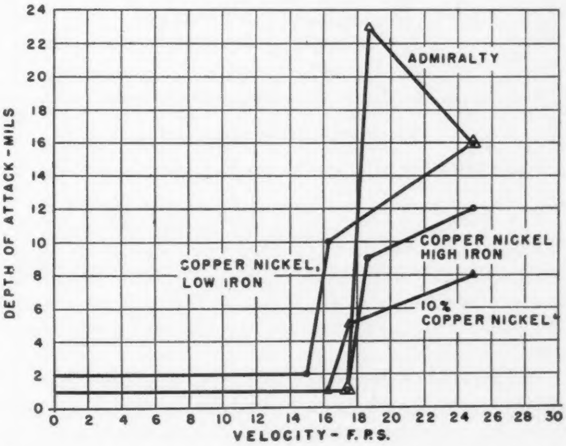

Figure 11—Effect of velocity on depth of attack in sea water at Kure Beach, N. C. Duration of test was 60 days.

It will be observed that in the case of iron the greatest attack occurs on the surfaces towards the center that move more slowly. The iron surfaces towards the periphery become passivated by the greater amount of oxygen that reaches them so that they become cathodic to the more slowly moving anodic surfaces towards the center and are given a substantial degree of cathodic protection.

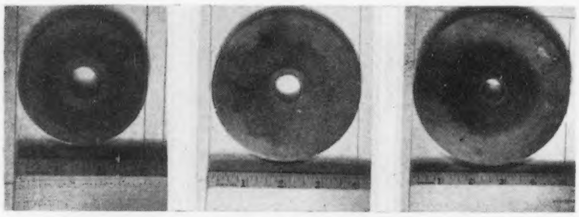

Figure 12—Cast iron discs used in rotating spindle test. Diameters of discs, reading left to right, are 3 inches, 4 inches and 5 inches. Test was conducted for 30 days at 15 C.

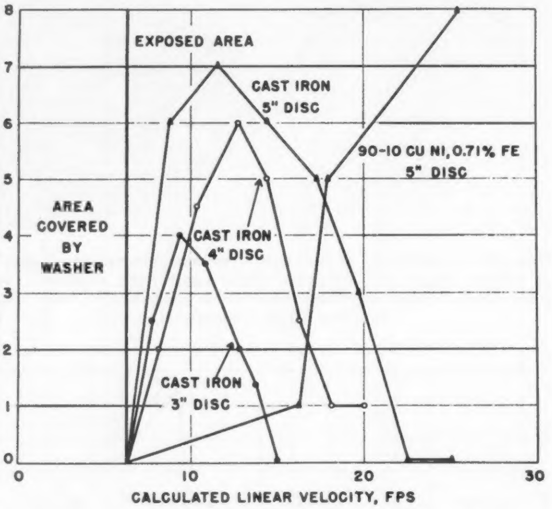

Figure 13—Effect of velocity on depth of attack in sea water.

For these reasons, results of tests with spinning discs are only relative. Comparisons should be made only amongst specimens having the same diameter, and surface finish and rotated at the same speed for the same length of time and preferably at the same time.

By attaching specimens to non-metallic discs at different radii and by appropriate electrical connections it is possible to observe and measure the differences in potential and flow of corrosion currents that are associated with different rates of movement or with the retention or loss of protective films.

A simple way to achieve a velocity effect is to use a specimen in the form of a tube or pipe through which water can be made to flow at any desired rate. Relatively short specimens—nipples—can be assembled in series by means of insulating couplings and attached to an appropriate manifold or flow box, such as shown in Figure 14.[18]

Electrical connections can be made to the outer surfaces of such tubular specimens in order to observe galvanic potentials or to combine metals in galvanic couples with means for measuring galvanic currents, as shown by Figure 15.

Jet Tests

An obvious way of subjecting a metal to the effects of highly localized turbulence is to place a submerged specimen in the path of a high velocity jet. This technique was developed to a high degree in British investigations of inlet end corrosion of condenser tubes started by G. D. Bengough and his associate R. May[19] and continued by the latter and his colleagues in the laboratories of the British Non-Ferrous Metals Research Association.[20] These investigators became impressed with the importance of entrained or entangled air bubbles as factors in impingement attack and developed fairly elaborate mixing chambers by which a measured amount of air could be introduced into the jet stream.

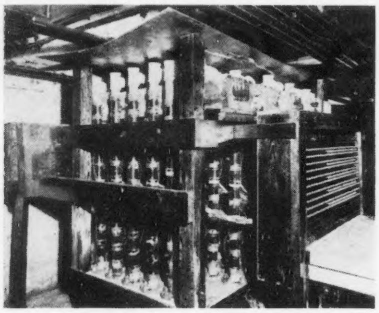

Figure 14—Flow box used in testing short samples.

They also provided means for controlling the size of the air bubbles which they considered to be critical, as described in their papers.

These British jet tests were carried out in laboratories remote from the sea so that it was necessary to transport sea water to the laboratories in carboys. Because of the limited supply, it was necessary to use the sea water over and over again in a recirculation system. Identical apparatus has been operated at the Inco test stations at Kure Beach and Harbor Island, N. C. (See Figure 16.)

At Kure Beach there is an unlimited supply of sea water which makes it possible to discard water after it has passed through the apparatus only once. Under otherwise identical testing conditions the once through water is much more aggressive to vulnerable materials such as aluminum brass, which does not demonstrate its usual advantage over Admiralty Brass in the once through tests. In order to get comparable results it is necessary to reduce the jet velocity in the once through tests to about 5 feet per second instead of the 15 feet per second velocity ordinarily used in the British tests with recirculated water. When the apparatus at Harbor Island is operated with recirculated water results are secured that agree well with the British results with their recirculated water.

Another peculiar result of the tests at Harbor Island is that in no case have air bubbles been found to be necessary to produce the impingement attack for which air bubbles are claimed to be essential in the British tests. These differences in results were examined and discussed in a paper by Gilbert and LaQue[21] from which the illustrative data in Tables 1 and 2 have been reproduced for convenient reference.

From the practical point of view, it has been possible to make a proper rating of condenser tube alloys

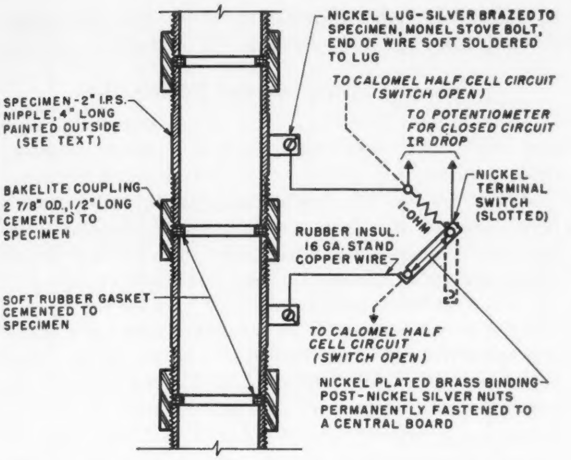
NICKEL LUG-SILVER BRAZED TO SPECIMEN, MONEL STOVE BOLT, END OF WIRE SOFT SOLDERED TO LUG
TO CALOMEL HALF CELL CIRCUIT (SWITCH OPEN)
TO POTENTIOMETER FOR CLOSED CIRCUIT IR DROP
SPECIMEN-2" I.P.S. NIPPLE, 4" LONG PAINTED OUTSIDE (SEE TEXT)
NICKEL TERMINAL SWITCH (SLOTTED)
BAKELITE COUPLING 2 7/8" O.D., 1/2" LONG CEMENTED TO SPECIMEN
1-OHM
RUBBER INSUL. 16 GA. STAND COPPER WIRE
SOFT RUBBER GASKET CEMENTED TO SPECIMEN
TO CALOMEL HALF CELL CIRCUIT (SWITCH OPEN)
NICKEL PLATED BRASS BINDING POST-NICKEL SILVER NUTS PERMANENTLY FASTENED TO A CENTRAL BOARD

Figure 15—Apparatus used to measure galvanic potentials of tubular specimens.

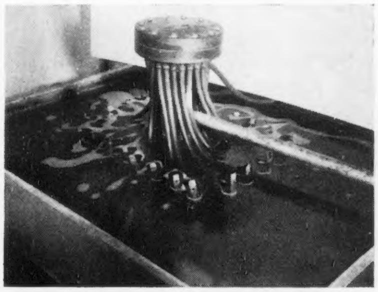

Figure 16—A recirculation system used in corrosion tests.

TABLE 1—Impingement Attack of Condenser Tube Alloys as Tested in Several Ways

MATERIAL	Recirculated water 15 ft/sec BNFMRA Lab.	15 ft/sec once thru water in England	Depth of Impingement Attack (mm)		
			15 ft/sec once thru water at Harbor Island	15 ft/sec Recirculated water at Harbor Island	4 ft/sec once thru water at Harbor Island
Arsenical Admiralty	0.34	0.11	0.28	0.28	0.15
70:30 Cupro-Nickel, 0.04% Fe.......	0.11	0.08	0.23	0.14	....
Arsenical Aluminum Brass......	0.04	0.07	0.20	0.01	....
90:10 Cupro-Nickel 1.5% Fe........	0.00[1]	0.10[1]	0.15	0.02	0.01
70:30 Cupro-Nickel 0.45% Fe.......	0.02[2]	0.09[2]	0.10	0.01	0.01

[1] 2% Iron.
[2] 0.8% Iron.

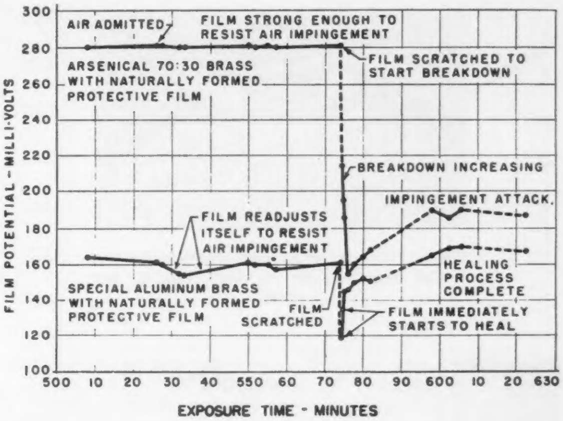

Figure 17—Film potential curves of arsenical 70-30 brass and aluminum-brass exposed to impingement attack.

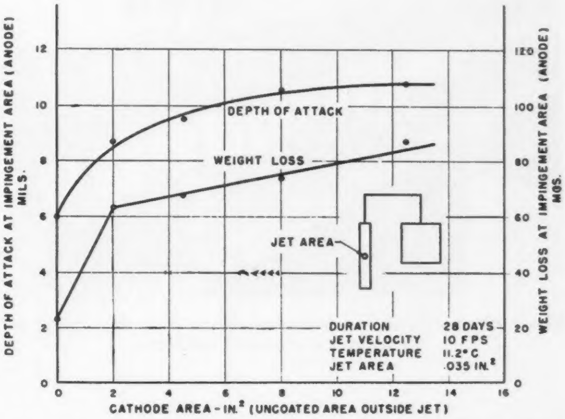

Figure 18—Corrosion of aluminum brass at impingement area versus exposed area outside of jet.

with respect to their resistance to impingement attack as it ordinarily may be encountered in condensers, by the use of either the British technique with recirculated water or the Harbor Island practice with once through water provided an appropriate jet velocity is employed. The condition must be severe enough to discriminate between good and poor alloys without being so drastic as to cause severe attack of all compositions.

Modifications of the jet test set-up have been devised so as to permit the electrical potentials of the areas under the jets to be measured during the course of a test.[22] By this means the formation and break down of protective films can be traced by changes in the potentials observed. The rate of repair of protective films destroyed deliberately by mechanical scratching also can be observed and thus an estimate of the ability of the alloy to recover from the effects of temporarily severe conditions can be made. Typical observations of this sort are shown by Figure 17.

Since the mechanism of jet impingement attack involves electrochemical action between the bare surfaces under a jet and the filmed surfaces away from it, it would be expected that the dimensions and area of the specimens might have an effect on the results. That this is the case was shown by tests in which the specimen on which the jet impinged was first increased in size and then connected electrically to other specimens of the same alloy submerged in relatively quiet water away from the jet stream. As the total area away from the jet was made larger (thus providing a larger cathode with less opportunity for cathodic polarization) the intensity of the attack under the jet was increased, as shown by the data in Figure 18.

For reproducible results, therefore, it is necessary

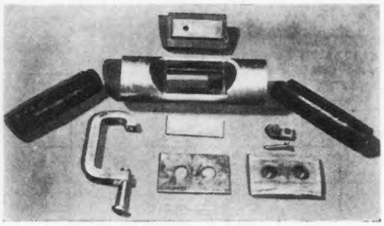

Figure 19—Apparatus (disassembled) for potential measurements in high velocity sea water.

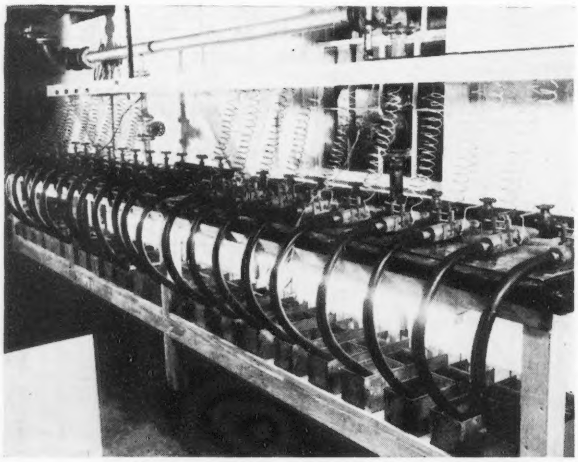

Figure 20—Apparatus used to control rate of flow of sea water over the surfaces of stationary specimens.

TABLE 2—Results of Jet Impingement Tests With British Non-Ferrous Metals Research Association Apparatus at Harbor Island, N. C.

Water System	% Air Added	Temp, Degrees C	Depth of Impingement Attack (mm)	
			Arsenical	
			Admiralty Brass	Aluminum Brass
Once through	3	18	0.37	No test
		20	0.36[1]	0.15[2]
		24	0.22	0.16
Once through	0	15	0.15	No test
		25	0.33	No test
Recirculated	3	20[3]	0.34[3,4]	0.04[3,5]
		30	0.25	0.01
Recirculated	0	25	0.27	0.00

Note: Duration of Test: 28 days
Velocity of Jet: 15 ft/sec

[1] Range 0.20 to 0.61.

[2] Range 0.08 to 0.23.

[3] Test made in England, 30-day run.

[4] Range 0.14 to 0.51.

[5] Range 0 to 0.66 (one specimen out of 20 pitted to depth of 0.66 mm. No impingement attack greater than 0.02 mm.)

TABLE 3—Potentials of Standard Half Cells (Potential Referred to Standard Hydrogen Electrode)

Half Cell	Voltage
Saturated Calomel	0.2415
Silver: Silver Chloride	0.2225
Copper: Copper Sulfate	0.316

to standardize the dimensions of jet test specimens. A common size is ½ inch x 3½ inches x $\frac{1}{16}$ inch.

Galvanic Potentials and Polarization

Since metals are frequently used in metallic contact with other metals in sea water there are many opportunities for galvanic action leading to accelerated corrosion of the less noble metal and galvanic protection of the more noble one. The probable direction of such galvanic action is indicated by an arrangement of metals in a galvanic series based on observed differences in potential in various metallic couples or on potentials as measured against a standard reference half cell. The most commonly used half cells in sea water potential measurement are the calomel half cells (the saturated one usually is favored), a silver: silver chloride half cell or, less commonly, a copper: copper sulfate half cell as used in underground cathodic protection investigations. For convenient reference, the potentials of these half cells at 25 C as referred to the standard hydrogen electrode are given in Table 3.

Since the potentials of metals in sea water are influenced by its oxygen content, temperature and velocity it is necessary to record and control these factors in any tests designed to yield reproducible results. The observed potentials also change—usually in the more noble direction as corrosion product films are formed. It is necessary, therefore, to continue the exposure until a stable film has developed and a steady potential has been reached. The time required for this to occur varies through wide limits but ordinarily an exposure of about two weeks under controlled conditions should suffice to yield reasonably steady and reproducible values.

The steady state and reproducibility of values are especially difficult to achieve with alloys such as the stainless steels which exhibit a sort of border-line passivity in sea water. These alloys frequently show widely fluctuating potentials as passivity is destroyed and restored in an erratic manner. Active potentials are especially favored by the occurrence of corrosion in the crevices that exist where the specimens are held in their supporting devices or fixtures.

Such potential measurements have been described and reported by LaQue and Cox[18] and by Huston and Teel.[23] A galvanic series based on such measurements is provided for convenient reference in Appendix B.

An apparatus[23] which permits ready control of the rate of flow of sea water over the surfaces of stationary specimens is shown by Figures 19 and 20. This apparatus is especially useful for studying polarization phenomena since a specimen of the metal to be polarized can be placed on one side of the chamber opposite a parallel platinum specimen which can serve as an anode for cathodic polarization or as a cathode for anodic polarization.

Since polarization in sea water is a function of time as well as current density it has been found desirable to use a single specimen for each current density to be investigated rather than to subject a single specimen to a series of increasing or decreas-

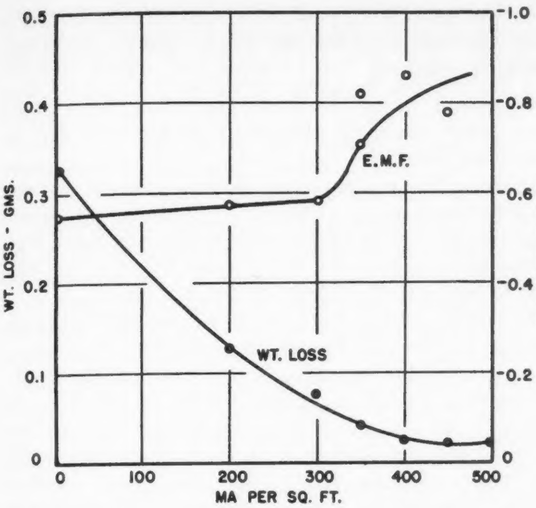

Figure 21—Cathodic polarization of low carbon steel in sea water flowing at 7.7 feet per second. Test area is 2.875 square inches.

ing current densities without allowing much time for equilibrium to be established at any one current density.

Applying a single and constant current density to each specimen permits observations of the effect of time on polarization and the establishment of relations between current density, potential and corrosion, as illustrated by the data for steel in Figure 21.

While it is possible to estimate the probable magnitude of galvanic effects from potential and polarization measurements it is usually desirable to measure galvanic action directly as by observing the differences in corrosion between coupled and uncoupled specimens exposed at and for the same time under identical conditions. This can be supplemented by measurements of current flow in couples. Care should be taken to keep the electrical resistance of the measuring circuit as low as possible (e.g., by using shunts of not more than 1 ohm resistance or in some cases by electrical hook-ups that introduce zero resistance in the galvanic circuit.)[24] In some cases the electrical arrangement can be as shown in Figure 15 where the current measuring shunt is made part of the circuit only when current is being measured. The current so measured will probably be less than would be flowing most of the time but the current measurements made in this way will provide another basis for comparing the relative galvanic action in different couples.

Since many of the factors such as polarization and resistance are affected by the current densities involved and by the geometry of the system it is necessary to take area effects into account in planning and interpreting galvanic corrosion tests. This was illustrated by a series of experiments with couples of iron and copper which yielded the data shown in Figure 22. From this, it may be concluded that most galvanic couple tests can yield only qualitative results which will apply directly only where identical area relationships and geometrical arrangements will exist.

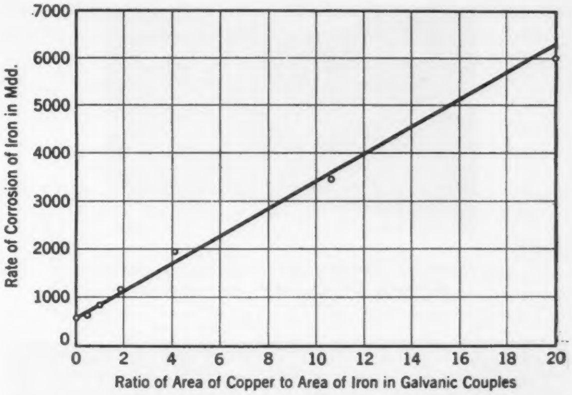

Figure 22—Effect of area of copper cathode on galvanic corrosion of iron anode in aerated 3 percent sodium chloride. Area of iron anodes is 0.047 sq dm; area of copper cathodes is 0.024 - 0.94 sq dm.

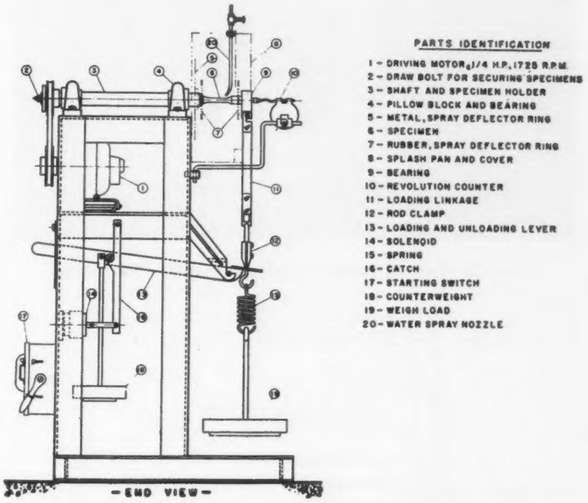
PARTS IDENTIFICATION
1 - DRIVING MOTOR, 1/4 H.P., 1725 R.P.M.
2 - DRAW BOLT FOR SECURING SPECIMENS
3 - SHAFT AND SPECIMEN HOLDER
4 - PILLOW BLOCK AND BEARING
5 - METAL, SPRAY DEFLECTOR RING
6 - SPECIMEN
7 - RUBBER, SPRAY DEFLECTOR RING
8 - SPLASH PAN AND COVER
9 - BEARING
10 - REVOLUTION COUNTER
11 - LOADING LINKAGE
12 - ROD CLAMP
13 - LOADING AND UNLOADING LEVER
14 - SOLENOID
15 - SPRING
16 - CATCH
17 - STARTING SWITCH
18 - COUNTERWEIGHT
19 - WEIGH LOAD
20 - WATER SPRAY NOZZLE
— END VIEW —

Figure 23—Rotating cantilever fatigue test apparatus.

Corrosion Fatigue Tests

The abilities of metals to withstand repeated stresses, as in the case of rotating shafts, etc., are reduced by the corrosive action of salt water. The corrosion fatigue limit thus established is much lower than the endurance limit in air. This is recognized, for example, in the testing of salt water pump shaft and propeller shaft materials. The test specimen is a carefully machined bar that is loaded as a beam while rotating at normal shaft speeds in contact with the salt water. Salt water is made to drip over the test specimen while it is being rotated under load, as shown in Figure 23.

Failure occurs eventually by cracking. Materials are rated in terms of corrosion fatigue limit which is the maximum value of repeated stress that the material will withstand for a specified number of applications of stress in the corrosive environments.

The effect of cyclic stress on corrosion rate may be illustrated very well by the results of laboratory tests that were designed to simulate the conditions encountered in ocean-going gasoline cargo tankers.

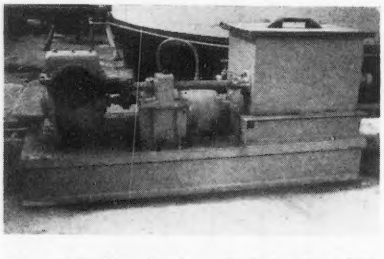

Figure 24—Overall view of device in which cantilever test specimens were exposed.

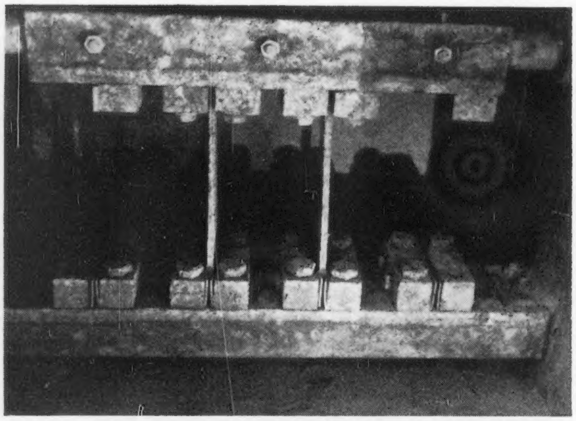

Figure 25—View of cantilever tests specimens in test device.

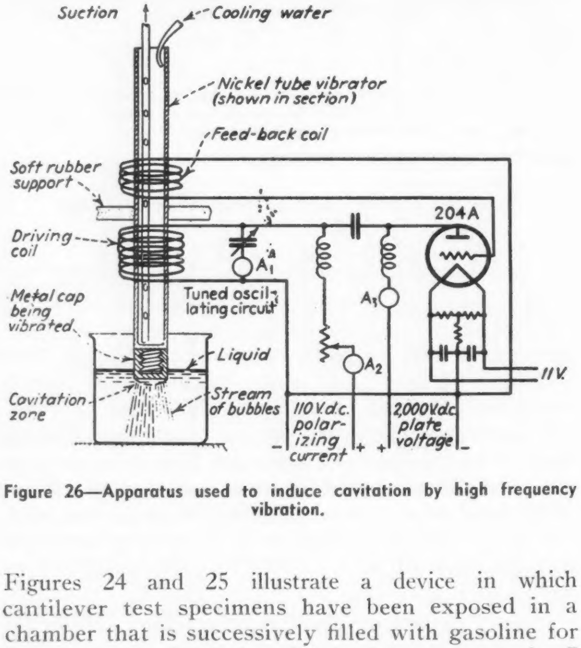

Figure 26—Apparatus used to induce cavitation by high frequency vibration.

Figures 24 and 25 illustrate a device in which cantilever test specimens have been exposed in a chamber that is successively filled with gasoline for 7 days, empty for 1 day, filled with sea water for 7 days and empty for 7 days. This cycle is repeated throughout the test period. Simple test bars exposed without applied stress along with tapered cantilever specimens of the same materials are simultaneously subjected to repeatedly applied reversing stresses. One-quarter inch thick by eight inch test specimens are deflected at one end 1/16 inch each way from the unstressed position. After 239 days carbon steel specimens under the cyclic stress conditions failed by cracking.

Corrosion rates on these specimens were more than twice those of the unstressed specimens, as shown in Table 4.

Presumably the repeated flexing caused the rust scale to break away from the stressed specimens and thus permit attack to proceed at the relatively high initial rate without the restraining effect of the rust that adhered to the unstressed specimens.

In tanker service the hull plates and bulkheads are subject to repeated flexing that results in conditions that cannot be reproduced by tests with simple specimens placed in the tankers. Service tests of carbon steel and low alloy high strength steels in the form of simple unstressed test coupons have ordinarily revealed no appreciable differences in their corrosion rates. In the laboratory cyclic stress test just described where the carbon steel specimens failed by cracking in 239 days a low alloy high strength steel has continued in test without cracking for more than 700 days. This better than 3:1 difference in performance under cyclic stress conditions would not have been predicted by tests of unstressed coupons.

Cavitation Erosion

There is no really good laboratory test for measuring the abilities of metals to resist damage by cavitation erosion in sea water. The method that has been used most frequently induces cavitation by high frequency vibration[25, 26, 27] achieved by magnetostriction (i.e., the change in length of a nickel tube or rod as it becomes magnetized and demagnetized in tune with a high frequency magnetic field.) In this connection refer to Figure 26.

Specimens attached to the nickel and vibrating with it suffer severe cavitation erosion. The erosion is so severe in fact that considerable damage occurs in 90 minutes—the usual duration of this sort of test. The principal defect of this method is that it gives a distorted result by exaggerating the mechanical forces in cavitation erosion at the expense of the corrosion phenomena which do not have time to contribute their proper share to the overall effect in the short time that the test runs. Thus hardness becomes more important than corrosion resistance in determining the relative merits of different metals and alloys in resisting cavitation erosion.

Comparing Corrosivities of Different Waters

Having established a reproducible rate of corrosion of a particular metal, such as iron (steel) or copper under specified reproducible conditions of

TABLE 4—Corrosion of Steels in Gasoline Sea Water Environment

SAMPLE	Corrosion Rate
Carbon Steel—Cyclic stress applied during test	.020 Ipy
Carbon Steel—No stress applied during test	.008 Ipy

exposure in salt water from a particular source it should be possible to compare waters from different sources as to their relative corrosivities—at least with respect to the metals used for comparison and under similar conditions of exposure. In view of these limitations on the significance of the comparisons there has not been much inclination to assess the corrosivity of salt water in this fashion.

However there has been a special interest in appraising the peculiar corrosivity of polluted salt waters. This has stemmed from investigations of impingement attack in jet tests carried out in laboratories—such as that of the British Non-Ferrous Metals Research Association—in which the water used for tests is transported and used over a considerable period of time. It was observed that standard materials, such as Admiralty Brass, corroded at greatly different rates under the same testing conditions in waters from different sources. This was particularly true with polluted brackish estuarine waters.

A more or less quantitative measure of the corrosivity of such waters was achieved in a standardized test which involved exposure of copper to corrosion by the waters under specified conditions.[28] The amount of copper in milligrams taken into solution under the prescribed testing conditions was called the Copper Corrosion Index. Unpolluted sea water of full salinity would show an index number under 10—frequently around 6 or 7. Polluted waters containing sulfides would show higher index number (e.g., as high as 30 in badly polluted waters.) These determinations had some value in characterizing waters and in providing a basis for explaining abnormally severe attack of standard materials or other apparent discrepancies in comparisons of different materials under nominally the same testing conditions.

Unfortunately, the Copper Corrosion Index figure for a particular water sample does not remain constant. It changes with the length and conditions of storage of the sample and may change during the progress of a particular test. These deficiencies were confirmed in several investigations at Harbor Island and after many attempts to use the test to rate or predict corrosivities of different water supplies the test was abandoned.

The author understands that this test is no longer used extensively by the British Non-Ferrous Metals Research Association investigators. Instead, they include specimens of a standard material—Admiralty Brass—in every test program and thereby provide a measure of the extent to which the results may be influenced by some peculiarity in the corrosivity of the water used for the test. A similar practice is used at the Harbor Island test station. There, however, the water is not polluted, has an almost constant salinity and, therefore, does not show much change in corrosivity from time to time beyond the natural seasonal effects of temperature and population of organisms.

Conclusion

On the basis of experience with corrosion testing in salt water over the past 20 years or so, the author has concluded that it is possible to reach sound and useful conclusions if tests are carried out carefully with proper control of the testing conditions and, most important, if the tests are planned properly and interpreted sensibly.

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Appendix A

Standard Specification for Substitute Ocean Water—American Society for Testing Materials Designation: D-1141-52(1)

Reagents

4. (a) **Stock Solution No. 1:** Dissolve the indicated amounts of the following salts in distilled water and dilute to a total volume of 7.0 liters. Store in well-stoppered glass containers.

$MgCl_2 \cdot 6H_2O$	3889.0 g
$CaCl_2$ (anhydrous)	405.6 g
$SrCl_2 \cdot 6H_2O$	14.8 g

(b) **Stock Solution No. 2:** Dissolve the indicated amounts of the following salts in distilled water and dilute to a total volume of 7.0 liters. Store in well-stoppered glass containers.

KCl	486.2 g
$NaHCO_3$	140.7 g
KBr	70.4 g
H_3BO_3	19.0 g
NaF	2.1 g

(c) **Stock Solution No. 3:** Dissolve the indicated amounts of the following salts in distilled water and dilute to a total volume of 10.0 liters. Store in well-stoppered amber glass containers.

$Ba(NO_3)_2$	0.994 g
$Mn(NO_3)_2 \cdot 6H_2O$	0.546 g
$Cu(NO_3)_2 \cdot 3H_2O$	0.396 g
$Zn(NO_3)_2 \cdot 6H_2O$	0.151 g
$Pb(NO_3)_2$	0.066 g
$AgNO_3$	0.0049 g

Note: To make the addition of $AgNO_3$ in the above solution, dissolve 0.049 g of $AgNO_3$ in distilled water and dilute to 1 liter. Add 100 ml of this solution to Stock Solution No. 3 before diluting to 10.0 liters.

Preparation of Substitute Ocean Water

5. Dissolve 245.34 g of NaCl and 40.94 g of anhydrous Na_2SO_4 in 8 to 9 liters of distilled water. Add slowly with vigorous stirring, 200 ml of Stock Solution No. 1 and then 100 ml of Stock Solution No. 2. Dilute to 10.0 liters. Adjust the pH to 8.2 with 0.1 N NaOH solution. Only a few milliliters of NaOH solution should be required.

Note: The solution should be prepared and the pH adjusted immediately prior to use.

Preparation of Substitute Ocean Water with Heavy Metals

6. Add 10 ml of Stock Solution No. 3 slowly, and with vigorous stirring, to 10.0 liters of the substitute ocean water prepared as described in Section 5.

Chemical Composition of Substitute Ocean Water(2), (3)

Compound	Concentration, grams per liter
NaCl	24.53
$MgCl_2$	5.20
Na_2SO_4	4.09
$CaCl_2$	1.16
KCl	0.695
$NaHCO_3$	0.201
KBr	0.101
H_3BO_3	0.027
$SrCl_2$	0.025
NaF	0.003
- - - - - - - - - -	- - - - - - - - - -
$Ba(NO_3)_2$	0.0000994
$Mn(NO_3)_2$	0.0000340
$Cu(NO_3)_2$	0.0000308
$Zn(NO_3)_2$	0.0000151
$Pb(NO_3)_2$	0.0000066
$AgNO_3$	0.00000049

(2) Chlorinity of this substitute ocean water is 19.38. Chlorinity, as used in these specifications, is an oceanographic term and is a measure of total halides in sea water which are precipitated by silver nitrate. It is numerically defined as the weight of silver required to completely precipitate the halogens in 0.3285 kg of ocean water.

(3) The pH (after adjustment with 0.1 N NaOH) is 8.2.

Note: The substitute ocean water prepared in accordance with Section 5 will have the composition shown above the broken line in this table. The substitute ocean water with heavy metals, prepared in accordance with Section 6, will have the complete composition shown in this table.

APPENDIX B—Arrangement of Metals and Alloys in a Galvanic Series Based on Potential Measurements in Sea Water

METAL	Steady Potential Negative to Saturated Calomel Half Cell, Volts
Zinc	1.03
Aluminum (Alclad 3S)	0.94
Aluminum 3S-H	0.79
Aluminum 61 S-T	0.76
Aluminum 52 S-H	0.74
Cast Iron	0.61
Carbon Steel	0.61
Stainless Steel Type 430 (17% chromium)¹	0.57
Ni-Resist Cast Iron (20% nickel)	0.54
Stainless Steel Type 304 (18% chromium, 8% nickel)¹	0.53
Stainless Steel Type 410 (13% chromium)¹	0.52
Ni-Resist Cast Iron (30% nickel)	0.49
Ni-Resist Cast Iron (20% nickel + copper)	0.46
Naval Rolled Brass	0.40
Yellow Brass	0.36
Copper	0.36
Red Brass	0.33
Composition G Bronze	0.31
Admiralty Brass	0.29
90:10 Cupro-Nickel (0.8% iron)	0.28
70:30 Cupro-Nickel (0.06% iron)	0.27
70:30 Cupro-Nickel (0.47% iron)	0.25
Stainless Steel Type 430 (17% chromium)¹	0.22
Nickel	0.20
Stainless Steel Type 316 (18% chromium, 12% nickel, 3% molybdenum)¹	0.18
Inconel	0.17
Stainless Steel Type 410 (13% chromium)¹	0.15
Titanium (commercial)	0.15
Silver	0.13
Titanium (high purity from iodide)	0.10
Stainless Steel Type 304 (18% chromium, 8% nickel)¹	0.08
Hastelloy C	0.08
Monel	0.08
Stainless Steel Type 316 (18% chromium, 12% nickel, 3% molybdenum)¹	0.05

Note: Velocity of flow: 13 ft./sec; Sea water temperature: 25 C (77 F)

[1] The stainless steels as a class exhibited erratic potentials depending on the incidence of pitting and corrosion in the crevices formed around the specimen supports. The values listed represent the extremes observed and due to their erratic nature should not be considered as establishing an invariable potential relationship amongst the alloys covered.

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(1) All the information given in Appendix A is from ASTM Standards; 1952, Part 7, Page 1242.

A Study of Current Distribution In Cathodic Protection*

By E. E. NELSON

E. E. NELSON is presently employed at the Brooklyn Laboratory of the Socony Mobil Oil Co. Formerly he worked in the Corrosion Branch of the Metallurgy Division, Naval Research Laboratory, Washington, D. C. He served for three years in the United States Navy and went to work at the Naval Research Laboratory in 1946 in the Electrochemistry Branch. In 1952 he was transferred to the Corrosion Branch where he has done work relating to the cathodic protection of ships. Projects of special interest have included the evaluation of galvanic electrodes, current distribution studies, and design of systems for ship installations. Mr. Nelson received a BS in chemical engineering in 1941 from the University of Cincinnati.

Abstract

An analysis is made of the effects of solution resistance and cathodic polarization on the current distribution in the cathodic protection of metals. Two of Kasper's formulas relating to the effect of resistance are discussed. Hoar and Agar's formula relating resistance and polarization to current distribution, presented as a background, was modified and used as the basis of a partially quantitative treatment of the relative importance of resistance and polarization in influencing current distribution. It is shown that resistances can have a much greater effect in this respect than polarization.

An experimental method of obtaining the current density on various parts of a large cathode is described and data obtained by this method are presented. These show the distribution of current on a large cathode in sea water as affected by the magnitude of applied current and by shields around the anode. Solution resistances are calculated from the data and compared with Kasper's formulas. Using previously published data for the resistance of paint films, calculations are presented showing the effect of paint films on current distribution. The advantages of good paint coatings in cathodic protection and the difficulties of cathodically protecting unpainted structures are discussed. **5.2.1**

Introduction

THE APPLICATION of theoretical formulas to potential gradient and current distribution between electrodes has been discussed by Kasper.[1] Assuming that the potential of the electrodes is uniform over their entire surface, it is shown that for an infinitely long cylindrical anode and an infinitely large plane cathode parallel to the anode, the current density is:

$$i = \frac{-AI}{\pi r^2} \tag{1}$$

where A is the perpendicular distance between the anode and cathode, I is the total current, and r is the distance from the axis of the anode to a point on the cathode at which the current density equals i. For a point anode and an infinite plane cathode the relationship is:

$$i = \frac{-AI}{2\pi r^3} \tag{2}$$

This derivation assumes either no polarization or uniform polarization and indicates the effect of solution resistance in determining relative current to various parts of the cathode.

Most practical anodes whether round, rectangular, or "D" shaped in cross section are a reasonably close approximation to cylinders of finite length and follow a relationship:

$$i = \frac{k}{r^n} \tag{3}$$

where the cathode is an infinite plane, k is a proportionality factor and n varies from 2 to 3. As the distance between anode and cathode increases relative to the length of the anode, n approaches 3. These formulas show that ratios of current densities on various areas are independent of resistivity and total current.

The case when the cathode is not an equipotential surface has been discussed by Hoar and Agar[2] who combine the effect of resistance and cathode potential on current distribution in the formula:

$$\frac{I_2}{I_1} = \frac{R_1 - \frac{\Delta Ec}{\Delta I}}{R_2 - \frac{\Delta Ec}{\Delta I}} \tag{4}$$

where I_1 and I_2 are the currents to two unit areas on a cathode, R_1 and R_2 are the respective resistance to these areas, ΔEc is the difference in potential of cathode areas 1 and 2, and ΔI is I_2 minus I_1. These authors emphasize that it is the slope of the cathode potential-current curve rather than the magnitude of the cathodic potential that influences current distribution. It is seen that when the slope of the potential-current curve is large compared to the resistances, the current distribution becomes more uniform. Conversely for relatively large resistances the current distribution is primarily dictated by the resistances.

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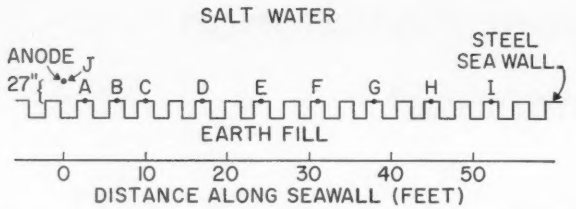

Figure 1—Plan of sea wall location of current distribution measurements. The individual pilings were welded together to give a continuous cathode. The water was 20 feet deep plus or minus 2 feet of tidal action. The letters designate the positions at which current density was measured.

Influence of Resistance and Polarization

Using concepts very similar to those discussed by Hoar and Agar,[2] a relationship can be derived showing the influence of resistance and polarization as proportional factors. The total voltage which drives the current from the anode to the cathode must overcome the resistance of the electrolyte, the bucking potential at the two electrodes, and the resistance of the metallic circuit. Since the bucking potential at the anode and the metallic resistance are common to all electrical paths between the anode and the various cathode areas they do not determine relative current densities. Subtracting the above quantities from the total voltage the potential is:

$$V = I_1R_1 + E_1 = I_2R_2 + E_2 \tag{5}$$

where I_1 and I_2 are the currents to two different unit areas on the cathode, R_1 and R_2 are the solution resistances to the respective areas, and E_1 and E_2 are the bucking potentials at these areas. If $E_1 = E_o + P_1$ and $E_2 = E_o + P_2$ where E_o is the open circuit potential of the cathode and P_1 and P_2 are the polarizations at the respective areas, then:

$$V - E_o = I_1R_1 + P_1 = I_2R_2 + P_2 \tag{6}$$

or setting $V - E_o = E$:

$$E = I_1R_1 + P_1 = I_2R_2 + P_2 \tag{7}$$

By rearranging the equations and dividing one by the other the following relationship is obtained:

$$\frac{I_2}{I_1} = \frac{R_1}{R_2}\,\frac{(E - P_2)}{(E - P_1)} \tag{8}$$

It follows from Equations (1) and (2) that R_1 and R_2 vary as the square of the distance in the first case discussed by Kasper, and as the cube of the distance in Kasper's second case. Therefore, a very large range in $\frac{R_1}{R_2}$ is possible in most field installations. The possible range of the ratio $\frac{(E - P_2)}{(E - P_1)}$ is very much less. For most practical cases with water or moist soil as the conducting medium, P_1 and P_2 may achieve a value not over 1.5 volts. Thus, in all cases where E is appreciably more than 1.5, the possible range of values of $\frac{E - P_2}{E - P_1}$ is small compared to the possible variations in $\frac{R_1}{R_2}$. It is only when E is just slightly larger than the greater of P_1 and P_2 that polarization can greatly influence the current ratio.

The study reported in this paper was undertaken to establish more quantitatively the relative importance of polarization and resistance on current distribution using full size models.

Experimental

A large steel retaining wall constructed of driven interlocking piling was selected as the cathode. The water area in front of this wall was free of any obstructions to electrical current flow such as piers or ships for a radius of more than 100 feet from the selected location of the anode. In plan view, as shown in Figure 1, the wall is corrugated with all the flat areas being approximately 2 feet wide. The joints between piles had been bonded with a weld that was 2 inches long in the direction of the joint, ½ inch long between the adjacent piles, and ½ inch thick. It is believed that this produced a sufficiently low electrical resistance for the 1500 foot length of the sea wall. The wall extended 10 feet above mean water level, 20 feet in the water and 10 feet in the earth bottom. Average tide was about ±2 feet. The surface of the wall had been painted when originally constructed but at the time of this test was essentially a bare rusted surface.

The water resistivity ranged from 50 to 60 ohm-cms with the value being essentially constant during any particular set of readings.

The anode was a "Duriron" rod 15 feet long and 2 inches in diameter, suspended vertically extending from 2½ feet below the water to approximately 2½ feet above the mud bottom. For most of the tests the anode was 27 inches out from the face of the wall.

Measurement of Current Density

Current density was measured at nine positions, as shown in Figure 1, by the letters A to I. The current density at these points was obtained by measuring the potential difference between two silver-silver chloride reference electrodes and dividing this difference by the water resistivity.

The principle of this method has been discussed and used by others.[3,4,5] For this method to be an accurate measure of current density, it is necessary only to have a homogeneous medium and a current which is fairly uniform to a distance from the reference electrodes equal to the spacing between the electrodes. As used in this series of tests two silver-silver chloride electrodes were mounted on a plastic strip one foot apart and the strip was suspended perpendicular to the sea wall with the one electrode 2 inches from the wall and the other 14 inches away.

In 50 ohm-cm water 1.64 mv are produced per ma/sq ft. This potential was measured with a 100,000 ohm-per-volt meter registering 50 mv full scale. The high resistance was to avoid polarization of the reference cells. The reference electrodes were found to have a maximum difference of 3 mv in their open

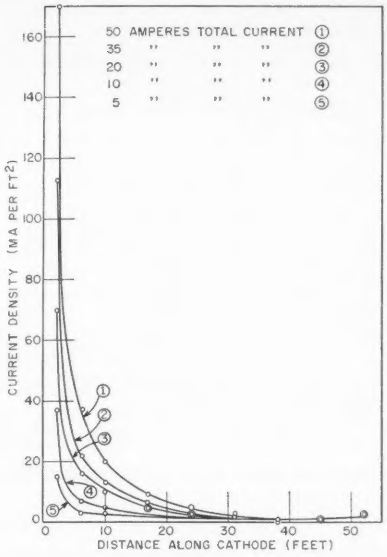

Figure 2—Current density as influenced by distance.

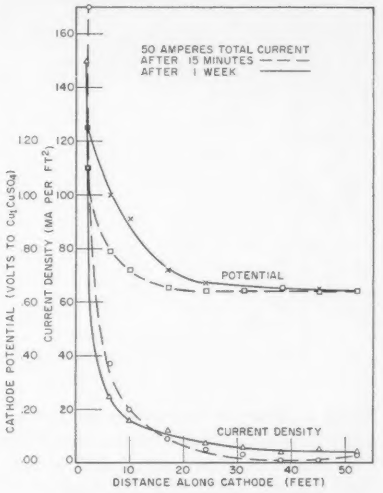

Figure 3—Effect of time on current distribution and potential. Total current to cathode equals 50 amperes. Dashed line represents data taken after current was on 15 minutes. The solid line is for data after one week.

circuit potential. This produced a maximum error of 2 ma/sq ft in the current density reading for which no correction was attempted.

A second source of error at small current densities was the naturally occurring corrosion currents that would affect the reading across the reference electrodes without correctly reflecting the current from the impressed voltage anode. These corrosion currents were measured both to and from the sea wall surface with values ranging up to 4 ma/sq ft. These, of course, were eliminated with increased applied current density and are considered a source of error only at the low current density readings.

The sea wall potential with respect to a copper-copper sulfate electrode was determined at all the lettered positions, A through J (Figure 1). The potential difference between J and any of the other lettered positions gives the IR drop in the solution between the anode and that position.

The total currents of 5, 10, 20, 35, and 50 amperes were successively applied to the cathode for short times. Each current was adjusted and after a lapse of 15 minutes the current density and potentials were read. Then the next higher current was applied and the readings were repeated. Following this the current was kept at 50 amperes for one week and the readings taken. Then the current was kept at 35 amperes for an additional week and the data taken. The data appear in Table 1 and are plotted in Figures 2, 3, and 4.

Effect of Shielding

The following test was run to show the effect of shielding. The "Duriron" rod was suspended only 12 inches from the sea wall with no shielding in place. Fifty amperes were then supplied to the sea wall cathode and readings were made. Then a thirty-inch wide strip of sheet plastic was suspended against the cathode so as to form a shield 15 inches wide on each side of the anode and extending from above the water line to the mud bottom. Fifty amperes were again used and the current densities at the lettered positions were determined. The shield was increased to 30 inches on each side of the anode and the test

TABLE 1—Current Densities and Potentials

POSITION	Distance Along Cathode Ft.	5 Amperes Total Current		10 Amperes Total Current		20 Amperes Total Current		35 Amperes Total Current		50 Amperes Total Current		50 Amperes Total Current Applied 1 Week		35 Amperes Total Current Applied 1 Week	
		1.*	2.**	1.*	2.**	1.*	2.**	1.*	2.**	1.*	2.**	1.*	2.**	1.*	2.**
A........	2.3	15	0.72	37	0.77	70	0.92	113	0.90	170	1.10	149	1.25	79	1.25
B........	6.25	3	0.69	7	0.68	16	0.71	22	0.74	37	0.79	25	1.00	12	1.05
C........	10	3	0.69	5	0.69	10	0.68	13	0.70	20	0.72	16	.91	9	.82
D........	17	5	0.66	5	0.66	5	0.65	7	0.66	9	0.65	13	.72	8	.71
E........	24	3	0.65	4	0.65	3	0.64	3	0.66	5	0.64	7	.67	4	.67
F........	31	2	0.64	2	0.66	—1	0.65	2	0.65	3	0.64	6	.65	4	.65
G........	38	—1	0.64	1	0.66	—1	0.65	0	0.65	1	0.65	4	.65	3	.66
H........	45	1	0.65	1	0.65	1	0.65	1	0.64	1	0.64	5	.65	—2	.65
I........	52	2	0.63	3	0.65	2	0.65	3	0.64	3	0.64	4	.64	2	.65
J........	—	—	1.01	—	1.51	—	2.2	—	2.85	—	3.6	—	3.70	—	2.50

1.* Current density to cathode (milliamperes per square foot.)
2.** Potential of cathode (volts negative to Cu-CuSO$_4$.)

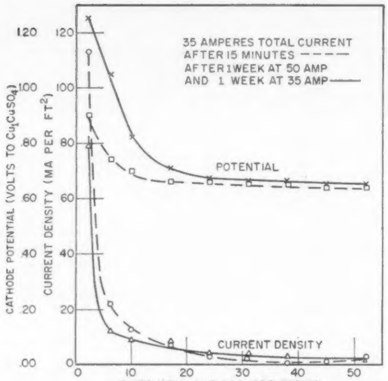

Figure 4—Effect of time on current distribution and potential. Dashed line represents data after 15 minutes at total current of 35 amperes. Solid line was taken after one week at 50 amperes followed by one week at 35 amperes.

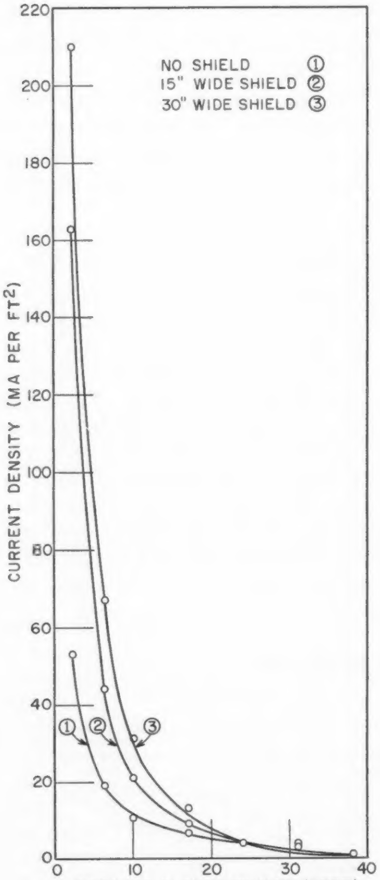

Figure 5—Effect of shielding on current distribution. The anode was suspended one foot from the steel cathode. Total current equals 50 amperes.

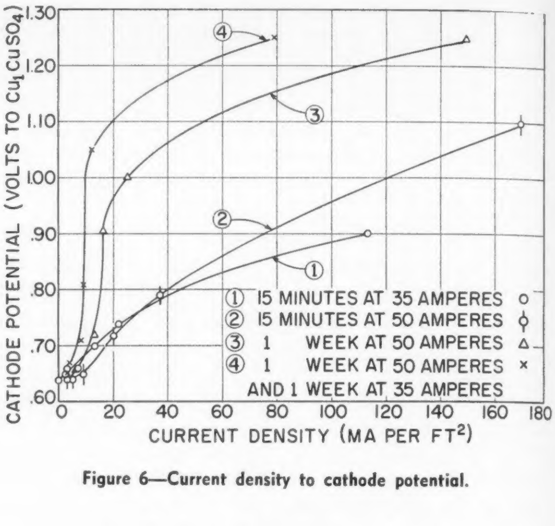

Figure 6—Current density to cathode potential.

TABLE 2—Effect of Shields on Current Distribution

POSITION	Distance From Anode Feet	No Shield ma/ft²	15″ Shield Each Side of Anode ma/ft²	30″ Shield Each Side of Anode ma/ft²
A	2.4	43	163	210
B	6.4	19	44	67
C	10	11	21	31
D	17	7	9	13
E	24	4	4	4
F	31	2	3	4
G	38	1	0	1
H	45	—1	—2	—1
I	52	—1	—1	—1

TABLE 3

POSITION	Volts E-P	Ohms R
A	1.25	15.8
B	1.45	138
C	1.68	187
D	1.79	224
E	1.83	457
F	1.85	463

made as before. The data are plotted in Figure 5 and recorded in Table 2. Curve 1 represents only that part of the current that could be measured between A and I. This neglects the current between the anode and A.

Figure 6 is plotted from the current density and potential data in Table 1. Curve 1 represents a total current of 35 amperes for 15 minutes, curve 2 is for 50 amperes after 15 minutes, curve 3 is for 50 amperes after 1 week, immediately followed by 35 amperes for 1 week to give curve 4.

Discussion

In Figure 2, the curves show that current density falls off very rapidly with distance from the anode. Curve 1 shows a range from 170 ma/sq ft at 2.3 feet to 20 ma/sq ft at 10 feet and on down to 3 ma/sq ft at 50 feet. Even with additional time for polarization to take effect the current distribution is still very non-uniform as indicated in Figures 3 and 4. Considering the solid curve for current density in Figure 4 and assuming 10 ma/sq ft as the desired current, it can be calculated that the excess current flowing to the overprotected area is 71 percent of the total current. Additionally, it can be seen that the area receiving 10 ma/sq ft or better extends only 10 feet on each side of the anode. This means that the areas farther away are left unprotected or must be protected by additional anodes. For the particular example being discussed, the current from a second anode at a distance of 40 feet would add to the current from the first anode so that all points between the anodes would be receiving over 10 ma/sq ft. A third anode placed an additional 40 feet away would add only slightly to the current density between the first two anodes.

Figure 5 shows that good insulating material covering the cathode adjacent to the anode aids in spreading the current to a wider area. Thus, a 30-inch shield on each side of the anode moved the 10 ma/sq ft position from a distance of 11 feet to 18 feet. However, the cathode area near the edge of the shield still received a large excess of current and the general shape of the curves was not affected. Surprisingly little, if any, effect was noted past the 25 foot position.

If the potentials of the cathode areas are subtracted from the potential readings taken at the anode as described above, the IR drops to each position are obtained. Dividing these IR drops by the corresponding current densities gives the resistance to each unit area. Referring to Equation (7) it is seen that this IR drop = E — P.

Table 3 shows E — P and R for the test in which the total current was 50 amperes for one week followed by 35 amperes for one week. For this calculation the readings of low current density were considered of little value since the local currents were relatively large compared to the impressed current. If the data in Table 3 are considered with the relation:

$$\frac{I_2}{I_1} = \frac{R_1}{R_2}\,\frac{(E - P_2)}{(E - P_1)}$$

it is seen that $\frac{R_1}{R_2}$ may vary from 1 to 29 while $\frac{E - P_2}{E - P_1}$ ranges from 1 to 1.48. Thus, resistance has a much greater effect in determining relative current than does polarization.

In Figure 7, the resistances calculated from the data in Table 1 excluding all values of less than 5 milliamperes are compared to the relations $R = kD^2$ and $R = kD^3$ where R is the resistance from the anode to a unit area of the cathode and D is the distance from the anode to the area. While it is not claimed that the data establish a straight line relationship, the points do cluster about the line $R = kD^2$ and the principal deviation is toward $R = kD^3$. This is in agreement with formulas (1) and (2).

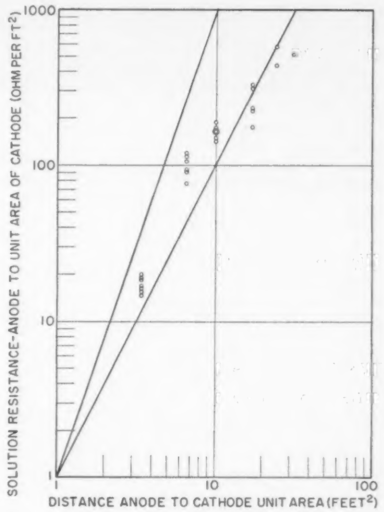

Figure 7—Solution resistance as a function of distance. Data are calculated from Table 1, excluding all values less than 5 milliamperes per square foot.

While the test data apply specifically to bare metal, the current ratio formula also can indicate the effect of paint. Bacon[6] et al state that for a number of paints which gave good corrosion protection the resistance was above 10^8 ohms per sq cm (roughly 10^5 ohms per sq ft). Thus, a "good" paint would add 10^5 ohms to both the numerator and denominator of R_1/R_2 making this factor very nearly 1 for all the distances considered in this present test. This would make polarization of prime importance and result in almost uniform current distribution. Paints that gave "fair" corrosion protection were stated to vary with time from 10^6 down to 10^2 ohms per sq ft. If this lower value is added to R_1 and R_2 of Table 2, the ratio of the extreme ranges is now only 4.9 compared to 29 for bare steel. In this case resistance would be about three times as effective as polarization in determining $\frac{I_2}{I_1}$. Paints giving "poor" corrosion protection were said to range from 10^6 initially down to 10 ohms per sq ft.

Conclusions

In cathodic protection systems, where possible, it is desirable to have a relatively large distance between the anode and cathode. This makes the ratio $\frac{R_1}{R_2}$ approach 1 for a large area of the cathode. Where this distance cannot be made large, such as is usually the situation on active ships, it would be extremely difficult to protect a bare ship. A great many anodes would be required and much of the current would be wasted on overprotected areas. A good paint system is very advantageous to the proper functioning of cathodic protection. Even with a good paint system some concern is felt that any bare area produced near the anode may reduce the current to more distant areas. It is believed that this effect should be investigated. It seems possible that the primary function of special shields surrounding the anodes may be avoidance of paint damage.

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Inhibiting Effect of Hydrofluoric Acid in Fuming Nitric Acid On Corrosion of Austenitic Chromium-Nickel Steels★

By CLARENCE E. LEVOE,(1) DAVID M. MASON(2) and JOHN B. RITTENHOUSE(3)

Abstract

The rate of corrosion of welded and unwelded chromium-nickel steels, Uniloy 19-9DL and 19-9DX and welded alloy 321 by fuming nitric acid in the liquid and the gas phase was measured with and without hydrofluoric acid added as a corrosion inhibitor. Corrosion by this system is of interest because of its widespread use as a rocket propellant. The effect of heat treatment on the corrosion process was measured by performing tests on one set of samples annealed at 1800 degrees F and air-cooled and on another series of samples that had been work-hardened and stress-relieved at 1200 degrees F. In general, samples in the latter condition had the least corrosion resistance. It was found that 0.6 weight percent hydrofluoric acid in fuming nitric acid inhibits both liquid- and gas-phase corrosion in all cases in which uncorroded metal was exposed to the acid. Most of the measurements were conducted at 130 and 160 degrees F although a few measurements were made at 100 degrees F to determine the effect of temperature on the corrosion process. Inhibition was also effective with temperature fluctuating between 70 and 160 degrees F. When the metal had previously undergone intergranular corrosion, however, the presence of hydrofluoric acid in fuming nitric acid aggravated the corrosive attack. **4.3.2**

Introduction

IN A PREVIOUS study[1] it was found that with aluminum alloys and certain steel alloys (including 19-9DL) which contain chromium and nickel, the presence of 0.2 to 1.0 weight percent hydrofluoric acid in fuming nitric acid markedly inhibits(4) the corrosive action of fuming nitric acid on these alloys. In the present report a detailed investigation of this inhibiting action on proprietary steels Uniloy 19-9DL and 19-9DX manufactured by the Universal-Cyclops Steel Corporation is described. Because of (1) ease of fabrication by welding, (2) high strength-to-weight ratio, and (3) relatively good corrosion resistance, these steels are used in guided missiles for the construction of pressure vessels which are to contain fuming nitric acid.

Stainless steels 19-9DL and 19-9DX are predominantly austenitic steels containing nominally 19 percent chromium and 9 percent nickel with molybdenum, tungsten, and carbon added to increase strength at room and elevated temperatures. Alloys of the general type of 18 percent chromium and 8 percent nickel with relatively high carbon content are susceptible to intergranular corrosion.[2] This susceptibility can be reduced by the addition of elements which have a greater affinity for carbon than does chromium; these elements are termed stabilizing elements. Thus in 19-9DL there are added as stabilizing elements 0.25 to 0.60 percent columbium (niobium) and 0.10 to 0.35 percent titanium; in 19-9DX the rather scarce element columbium has been eliminated, and the titanium content increased to 0.40 to 0.75 percent. Although these two steels contain stabilizing elements, the quantity of these elements is insufficient to prevent intergranular corrosion completely. When these steels are heated in the temperature range 850 to 1650 degrees F, there is a tendency for the carbon which is originally in solid solution, in the austenite, to combine with chromium and form chromium carbides. The formation of these carbides in certain regions of the metal depletes the adjacent area of chromium and thus renders the impoverished area susceptible to corrosion. The carbides generally form at grain boundaries, and thus there is a tendency for corrosion to proceed along the chromium-impoverished grain boundaries.

If these alloys are annealed for two hours at 1800 degrees F and rapidly cooled (herein called heat treatment A), a homogeneous austenitic structure is formed, carbon remaining in solid solution and chromium remaining evenly distributed throughout the alloys. In this condition the alloys are most corrosion-resistant; however, the mechanical properties are relatively low (100,000-psi ultimate strength and 55,000-psi yield strength). If the steel is work-hardened and stress-relieved at 1200 degrees F under these conditions (heat treatment B), chromium carbide precipitation at the grain boundaries is increased, and the steel becomes susceptible to intergranular corrosion. In this work-hardened condition however the properties of the material are high (120,000-psi ultimate tensile strength and 90,000-psi yield strength). In order to make structures with high strength-to-weight ratios, the work-hardened material is used whenever possible.

When these alloys in either condition are welded, the area adjacent to the weld is heated in the temperature range 850 to 1650 degrees F; thus this area is rendered susceptible to intergranular corrosion. In the present investigation, studies were made on welded and unwelded 19-9DL and 19-9DX in both the annealed and the work-hardened conditions.

It has been established in the case of passivation of aluminum alloys by hydrofluoric acid in fuming

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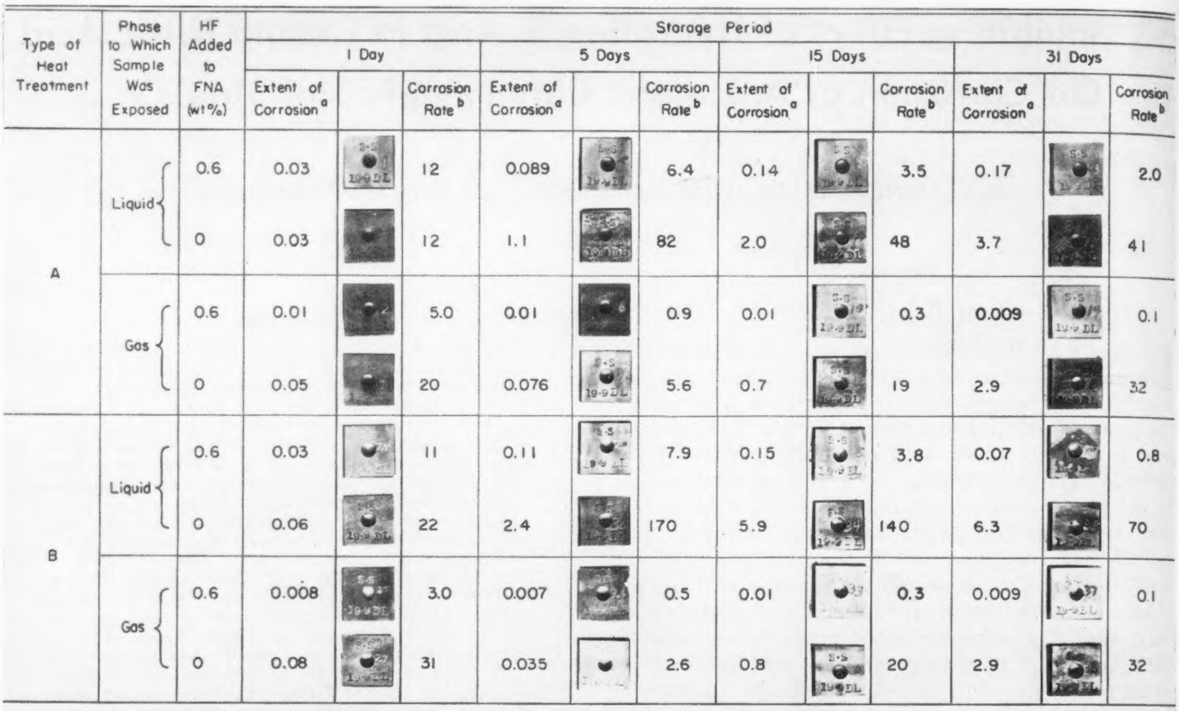
(4) Throughout this report the term inhibited fuming nitric acid refers to fuming nitric acid which contains amounts of hydrofluoric acid in this composition range.



Type of Heat Treatment	Phase to Which Sample Was Exposed	HF Added to FNA (wt%)	Storage Period											
			1 Day			5 Days			15 Days			31 Days		
			Extent of Corrosion[a]		Corrosion Rate[b]	Extent of Corrosion[a]		Corrosion Rate[b]	Extent of Corrosion[a]		Corrosion Rate[b]	Extent of Corrosion[a]		Corrosion Rate[b]
A	Liquid	0.6	0.03		12	0.089		6.4	0.14		3.5	0.17		2.0
		0	0.03		12	1.1		82	2.0		48	3.7		41
	Gas	0.6	0.01		5.0	0.01		0.9	0.01		0.3	0.009		0.1
		0	0.05		20	0.076		5.6	0.7		19	2.9		32
B	Liquid	0.6	0.03		11	0.11		7.9	0.15		3.8	0.07		0.8
		0	0.06		22	2.4		170	5.9		140	6.3		70
	Gas	0.6	0.008		3.0	0.007		0.5	0.01		0.3	0.009		0.1
		0	0.08		31	0.035		2.6	0.8		20	2.9		32

[a] Extent of corrosion (mils) was determined by measuring weight loss of sample of known area and density.

[b] Corrosion rate (mils/yr) was calculated by dividing corrosion depth by storage time expressed in years (365 days/yr).

Figure 1—Samples of Uniloy 19-9DL steel exposed to fuming nitric acid at 130 F.

TABLE 1—Chemical Analyses of Steels Tested

ELEMENT	COMPOSITION OF ELEMENT (Wt. %)[1]									
	19-9DL AMS5526[2,3]	19-9DX AMS5538[2,3]	AISI 321[2]	Unwelded Samples		Welded Samples		Weld Metal		
				19-9DL	19-9DX	19-9DL	19-9DX	19-9DL	19-9WX Type 1	19-9WX Type 2
Carbon	0.28 to 35	0.28 to 35	0.10 max.	0.29	0.35	0.34	0.32	0.08	0.12	0.14
Manganese	0.75 to 1.50	0.75 to 1.50	2.00 max.	....	....	....	....	....	....	....
Silicon	0.30 to 0.80	0.30 to 0.80	1.00 max.	....	....	....	....	....	....	....
Phosphorus	0.040 max.	0.040 max.	0.040 max.	....	....	....	....	....	....	....
Sulfur	0.030 max.	0.030 max.	0.030 max.	....	....	....	....	....	....	....
Chromium	18.00 to 21.00	18.00 to 21.00	17.00 to 19.00	18.19	18.34	18.55	18.23	21.40	20.66	21.46
Nickel	8.00 to 11.00	8.00 to 11.00	8.00 to 11.00	9.11	9.10	8.85	9.84	8.64	9.01	98.82
Molybdenum	1.00 to 1.75	1.25 to 2.00	....	1.05	1.39	1.43	1.33	0.51	0.52	0.48
Tungsten	1.00 to 1.75	1.00 to 1.75	....	1.50	1.00	1.51	1.27	1.32	2.14	0.99
Niobium and tantalum	0.25 to 0.60	....	....	0.60	0.40	0.36	nil	1.29	0.45	1.17
Titanium	0.10 to 0.35	0.40 to 0.75	min of 5 x wt % C	0.15	0.60	0.15	0.44	0.27	nil	nil
Copper	0.50 max.	0.50 max.	....	....	....	....	....	....	....	....

[1] Dashes indicate that no analysis was made or given.

[2] These analyses were provided by the manufacturer and refer to average steels. The other analyses were made on the actual steel samples used in this investigation.

[3] These steels meet the Aeronautical Material Specifications (AMS).

nitric acid, that a tenacious precipitate of aluminum fluoride forms on the surface of the metal, protecting it from corrosive attack. In the case of stainless steels the chemical nature of the passivating coating has not been definitely established although there is evidence that either chromium or nickel fluoride (or both), when formed on the surface of the metal, is responsible for the passivation process. Because of the solubility mechanism for the passivation process, a coating which forms on a metal dissolves if the metal is exposed to a fresh sample of fuming nitric acid. Since hydrofluoric acid is extremely volatile, storage vessels should not be opened unnecessarily, thus risking the loss of hydrofluoric acid and the removal of the passivating layer.

Methods and Materials

In studying the extent of corrosion of samples the weight-loss method was used. The apparatus used is described in detail elsewhere.[3] Small square samples were placed on a Teflon(5) rod and held in a given position by means of a tight fit between the rod and a hole in the middle of the sample. The

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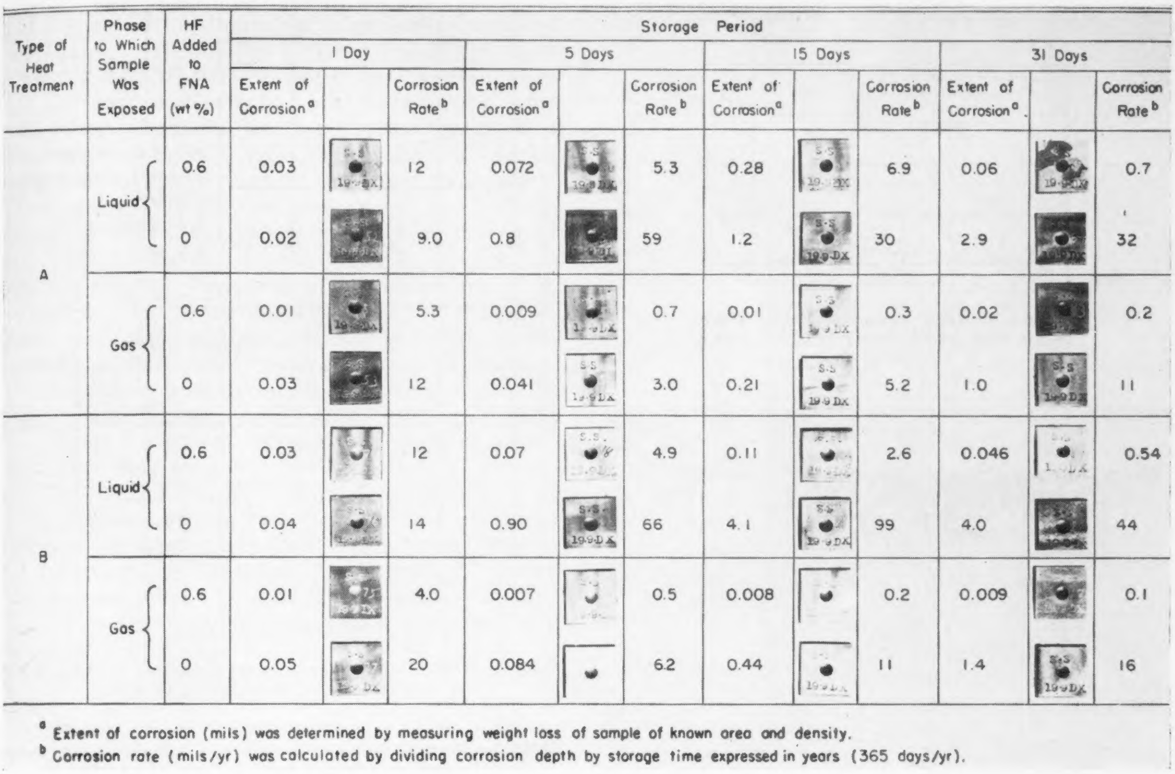
(5) A solid fluorinated ethylene polymer very resistant to fuming nitric acid and manufactured by du Pont de Nemours Co.



Type of Heat Treatment	Phase to Which Sample Was Exposed	HF Added to FNA (wt %)	Storage Period							
			1 Day		5 Days		15 Days		31 Days	
			Extent of Corrosion[a]	Corrosion Rate[b]	Extent of Corrosion[a]	Corrosion Rate[b]	Extent of Corrosion[a]	Corrosion Rate[b]	Extent of Corrosion[a]	Corrosion Rate[b]
A	Liquid	0.6	0.03	12	0.072	5.3	0.28	6.9	0.06	0.7
		0	0.02	9.0	0.8	59	1.2	30	2.9	32
	Gas	0.6	0.01	5.3	0.009	0.7	0.01	0.3	0.02	0.2
		0	0.03	12	0.041	3.0	0.21	5.2	1.0	11
B	Liquid	0.6	0.03	12	0.07	4.9	0.11	2.6	0.046	0.54
		0	0.04	14	0.90	66	4.1	99	4.0	44
	Gas	0.6	0.01	4.0	0.007	0.5	0.008	0.2	0.009	0.1
		0	0.05	20	0.084	6.2	0.44	11	1.4	16

[a] Extent of corrosion (mils) was determined by measuring weight loss of sample of known area and density.

[b] Corrosion rate (mils/yr) was calculated by dividing corrosion depth by storage time expressed in years (365 days/yr).

Figure 2—Samples of Uniloy 19-9DX steel exposed to fuming nitric acid at 130 F.

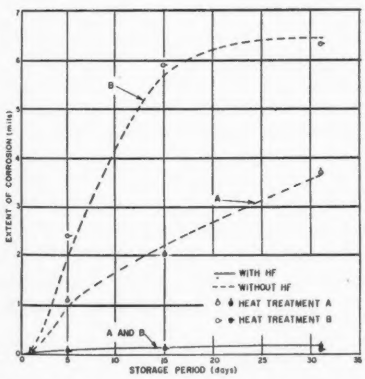


Figure 3—Extent of corrosion of Uniloy 19-9DL by liquid-phase fuming nitric acid at 130 F as a function of time.

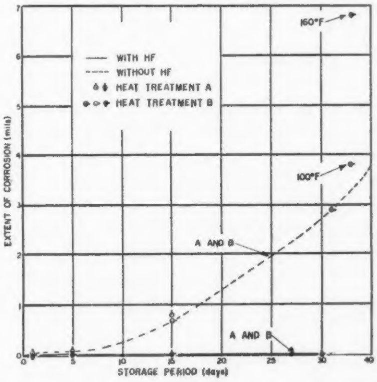


Figure 4—Extent of corrosion of Uniloy 19-9DL by gas-phase fuming nitric acid at 130 F as a function of time.

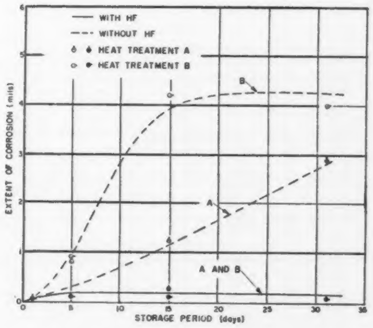


Figure 5—Extent of corrosion of Uniloy 19-9DX by liquid-phase fuming nitric acid at 130 F as a function of time.

samples were then placed in a Teflon-lined aluminum 61S-T6 vessel which was provided with a pressure-tight closure. The Teflon liner had a 1.0 inch inside diameter and was 5.0 inches deep. The vessel was half-filled with fuming nitric acid. Samples on the bottom of the rod thus were exposed to liquid phase, and samples on top of the rod were exposed to gas phase. The ratio of the surface of metal exposed to the volume of acid in the liquid phase as well as in the gas phase was about 1.4 sq in/cu in. The vessels were completely immersed in a constant-temperature water bath maintained within 0.2 degree F of the desired temperature in the range 100 to 160 degrees F.

TABLE 2—Chemical Composition of Fuming Nitric Acid Samples

Component	Composition (Wt. %)	
	Of Inhibited Acid	Of Uninhibited Acid
HNO_3	82.8	84.4
NO_2	13.4	13.1
H_2O	3.2	2.5
HF	0.6	0

After the storage period the samples were removed, washed, and dried. Next the surface of the metal was rubbed with an eraser to remove mechanically as much nonmetallic coating as possible. Each sample was then weighed, and the weight loss

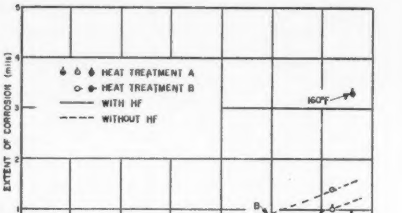


Figure 6—Extent of corrosion of Uniloy 19-9DX by gas-phase fuming nitric acid at 130 F as a function of time.

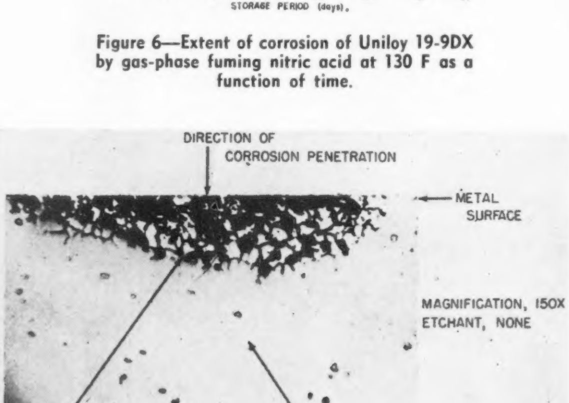


Figure 7—Photomicrograph of Uniloy 19-9DL intergranularly corroded by unihibited liquid-phase fuming nitric acid. Actual magnification of photograph after reduction for reproduction purposes is 53X.

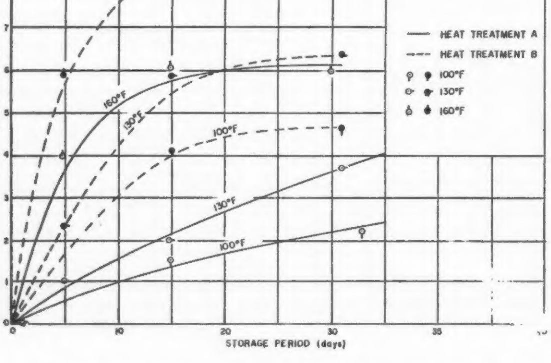


Figure 8—Effect of temperature on extent of corrosion of Uniloy 19-9DL by unihibited liquid-phase fuming nitric acid.

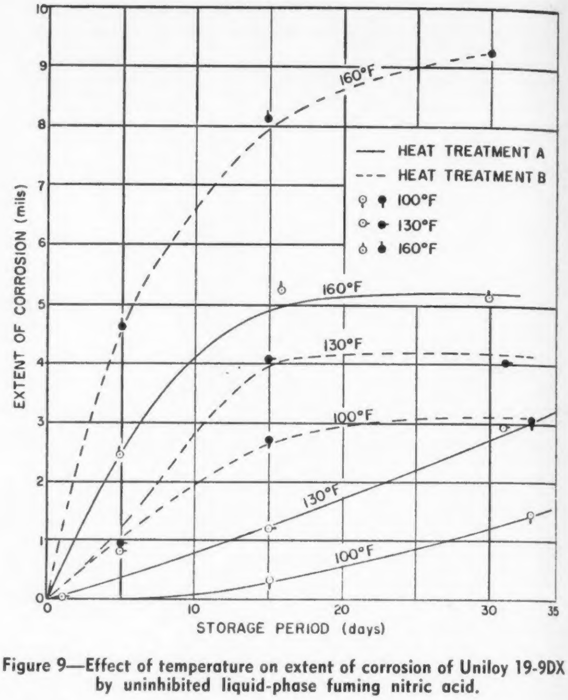


Figure 9—Effect of temperature on extent of corrosion of Uniloy 19-9DX by uninhibited liquid-phase fuming nitric acid.

TABLE 3—Effect of Previous Corrosion of Sample on Subsequent Corrosion by Inhibited Fuming Nitric Acid at 130 F

	EXTENT OF CORROSION (mils)	
ALLOY[1]	Samples in Uninhibited Fuming Nitric Acid[2] (Test 1)	Samples from Test 1 in Inhibited Fuming Nitric Acid[2] (Test 2)
19-9DL...........	10.0 to 10.2	19 to 21
19-9DX..........	0.58 to 0.55	3.9 to 4.0

[1] Work-hardened at 1200 F and stress-relieved at 1200 F, identified as heat treatment B.

[2] Samples were exposed to liquid-phase fuming nitric acid for 15 days.

due to corrosion was determined. This weight loss, divided by the product of the exposed area and the density of the sample, was assumed to give the extent of corrosion.

Chemical analysis of the specific steels and the welding wires tested is shown in Table 1. Fuming nitric acid of the initial composition given in Table 2 was used in these tests. Since acid of this composition is stable with respect to thermal decomposition,[1] changes of composition were due mainly to the corrosion process. In the most severe case of corrosion the NO_2 content of the acid after storage had increased by about 7.0 weight percent absolute. In cases in which passivation occurred, the composition of the acid was very slightly altered during storage.

Results

Corrosion of Unwelded Metal Specimens

1. Inhibiting Effect of HF on Corrosion Process. The results of corrosion tests at 130 degrees F on Uniloy 19-9DL and 19-9DX are shown in Figures 1 and 2, respectively, where actual photographs of samples after exposure to liquid- and gas-phase fuming nitric acid are included. Both the extent and the rate of corrosion are indicated in these figures. The inhibiting effect of HF on the corrosion is both visually and numerically evident in Figures 1 and 2 by a comparison, for example, of the data for samples exposed 31 days. In general, the corrosion is less severe on 19-9DX than on 19-9DL for the case of uninhibited liquid- and gas-phase acid. These data are reproduced in Figures 3 through 6 in which the extent of corrosion is plotted vs time for the various sets of conditions. From these figures it is evident that HF markedly inhibits both liquid- and gas-phase corrosion of 19-9DL and 19-9DX. From the slope of the curves for inhibited acid at 30 days it appears that the corrosion rate has approached zero. This behavior is probably due to the formation of a tenacious coating which is impervious to fuming nitric acid and thus protects the metal underneath.

It is noteworthy that in some cases in which inhibition occurred, the extent of corrosion decreased with time. This anomaly probably is due to the fact that it is impossible to remove the passivating layer completely; thus the indicated weight of uncorroded metal is too high, and the extent of corrosion correspondingly low.

It is evident from comparisons of Figure 3 with Figure 4 and Figure 5 with Figure 6 that in 31 days the gas-phase corrosion is less severe than the liquid-phase corrosion for both 19-9DL and 19-9DX with both HF-inhibited and uninhibited acid. However, the corrosion-time curves for uninhibited gas-phase acid are usually concave upward at 30 days, whereas the corresponding liquid-phase curves are usually concave downward. Thus at greater periods of time than 30 days the extent of gas-phase corrosion may exceed that of the liquid phase.

It appears in cases of heat treatment B (see Figures 3 and 5) that without inhibition the corrosion rate after 30 days becomes quite low. This behavior is not understood although changes in composition of the acid resulting from the corrosion process for this period of storage (in which case the H_2O and NO_2 will have increased greatly) may partly explain the behavior. It should be pointed out, however, that particularly in heat treatment B the alloys are susceptible to intergranular corrosion, and the overall corrosion displayed in Figures 3 and 5 do not reflect the local severity of attack. Shown in Figure 7 is a photomicrograph displaying this type of corrosion for a sample of 19-9DL in heat treatment A exposed to uninhibited liquid-phase fuming nitric acid for 30 days at 130 degrees F. Accompanying this type of corrosion is pitting of the samples; the extent of corrosion based on over-all behavior may not reflect the severity of corrosion locally at pitted areas. In acid containing 0.6 weight percent HF, intergranular corrosion has not been observed, and corrosion in both gas- and liquid-phase is minimized.

2. Effect of Previous Corrosion of Sample on Inhibition Process. It has been found that when a sample of 19-9DL or 19-9DX has undergone severe corrosion by exposure of uninhibited fuming nitric acid, subsequent exposure to HF-inhibited acid results not in passivation but in extremely severe corrosion. This behavior makes it imperative that, in order to ensure inhibition, the sample be exposed only to HF-inhibited fuming nitric acid from the outset. This effect can be seen in results for test 2 in Table 3, where much more severe corrosion results than would be expected for HF-inhibited fuming nitric acid is shown by a comparison with the data of Figures 1 and 2.

In the fabrication of parts from 19-9DL or 19-9DX it is often desirable to clean the surfaces by pickling.

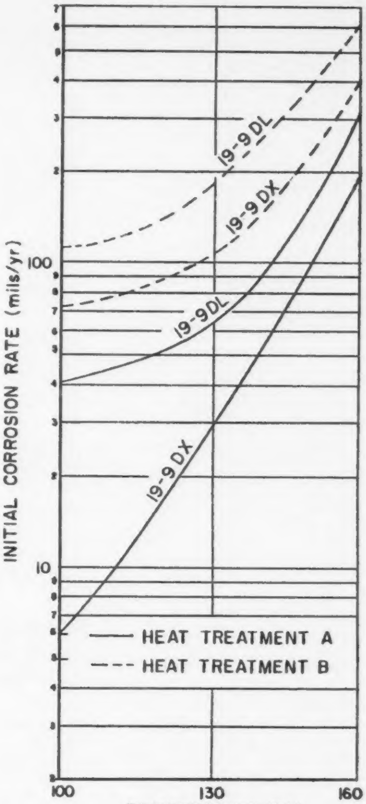


Figure 10—Effect of temperature on initial rate of corrosion of Uniloy 19-9DL and 19-9DX by uninhibited liquid-phase fuming nitric acid.

TABLE 4—Effect of Temperature on Extent of Corrosion of Uniloy 19-9DL and 19-9DX by Uninhibited Liquid-Phase Fuming Nitric Acid

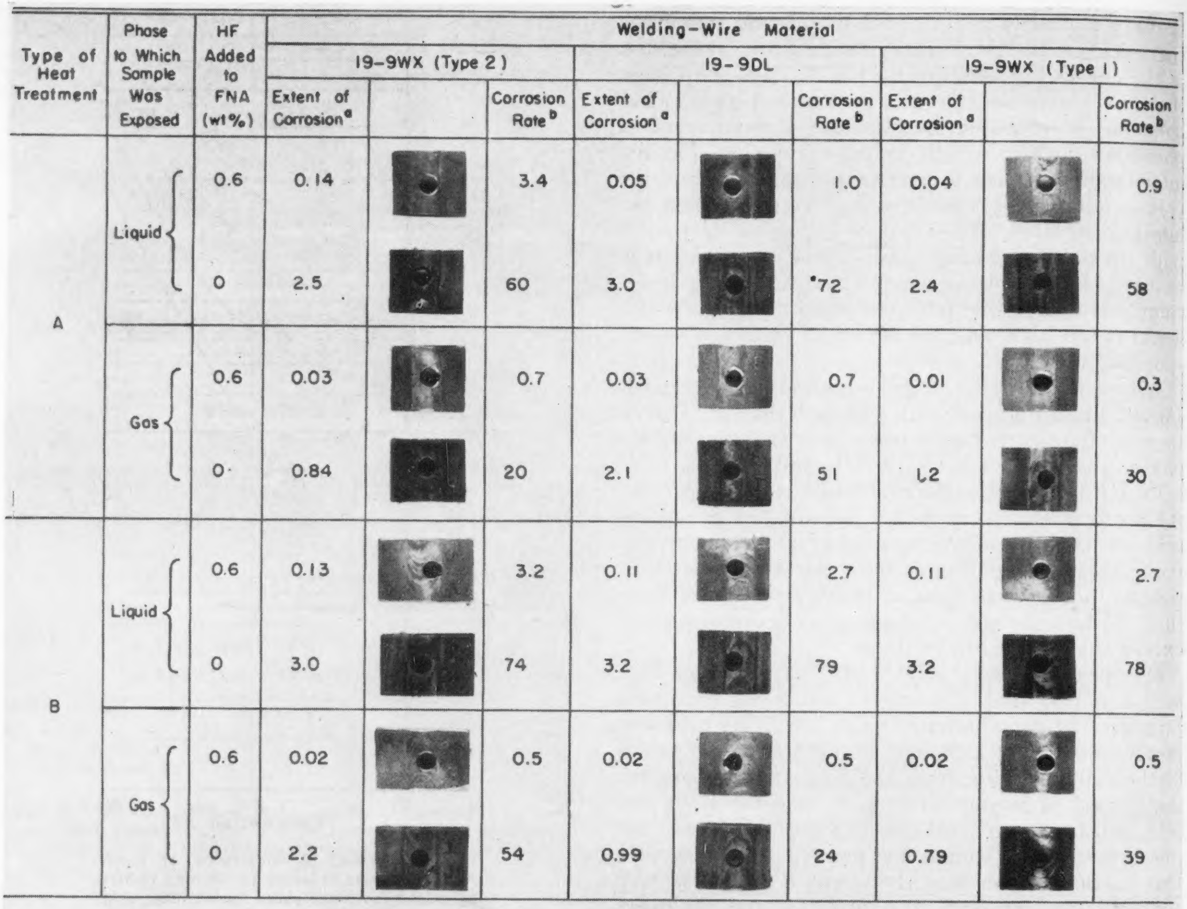
Temperature (Degrees F)	Alloy	Type of Heat Treatment[1]	Extent of Corrosion (mils)		
			At 5 Days	At 15 Days	At 33 Days
100........	19-9DL	A	..	1.5	2.2
		B	..	4.1	4.6
					3.8[2]
	19-9DX	A	..	0.3	1.4
					0.9[2]
		B	..	2.7	3.0
160........	19-9DL	A	4.0	6.0	6.0
		B	5.9	8.7	8.3
					6.8[2]
	19-9DX	A	2.4	5.2	5.1
					3.3[2]
		B	4.6	8.1	9.2

[1] Heat treatment A: annealed 2 hours at 1800 F and air-cooled. Heat treatment B: work-hardened and stress-relieved at 1200 F.

[2] Exposure to gas phase.

One treatment often used involves a 30-minute pickle in a 30 weight percent aqueous solution of HNO_3 at 60 to 80 degrees F. Subsequent exposure to HF-inhibited fuming nitric acid resulted in passivation. Thus this pickling procedure appears to be suitable.

Another treatment consists of exposure for 45 minutes to 15 weight percent HNO_3 and 2 weight percent HF at 135 degrees F. In this treatment severe pitting of the sample occurred and on subsequent exposure to inhibited fuming nitric acid at 130 degrees F for eight days, indications of severe local



Type of Heat Treatment	Phase to Which Sample Was Exposed	HF Added to FNA (wt%)	Welding-Wire Material								
			19-9WX (Type 2)			19-9DL			19-9WX (Type 1)		
			Extent of Corrosion[a]		Corrosion Rate[b]	Extent of Corrosion[a]		Corrosion Rate[b]	Extent of Corrosion[a]		Corrosion Rate[b]
A	Liquid	0.6	0.14		3.4	0.05		1.0	0.04		0.9
		0	2.5		60	3.0		72	2.4		58
	Gas	0.6	0.03		0.7	0.03		0.7	0.01		0.3
		0	0.84		20	2.1		51	1.2		30
B	Liquid	0.6	0.13		3.2	0.11		2.7	0.11		2.7
		0	3.0		74	3.2		79	3.2		78
	Gas	0.6	0.02		0.5	0.02		0.5	0.02		0.5
		0	2.2		54	0.99		24	0.79		39

[a] Extent of corrosion (mils) was determined by measuring weight loss of sample of known area and density. Local attack near weld is appraised visually.

[b] Corrosion rate (mils/yr) was calculated by dividing depth of corrosion by storage time expressed in years (365 days/yr).

Figure 11—Samples of welded 19-9DL steel exposed to fuming nitric acid for 15 days at 130 F.

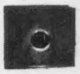
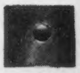
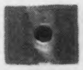
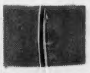
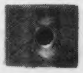
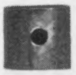
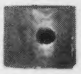
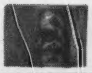
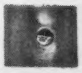
pitting were present. Thus this pickling treatment is not recommended unless the pitted surface is machined thoroughly to remove the pits. Evidently the HF in aqueous nitric acid pickling solutions accelerates the corrosion process and causes pits which are susceptible to aggravated attack on exposures to HF-inhibited fuming nitric acid.

3. Effect of Temperature on Corrosion by Uninhibited Acid. As would be expected from normal reaction-kinetic behavior, an increase in temperature increases the rate of corrosion. Table 4 shows the effect of temperature on extent of corrosion of Uniloy 19-9DL and 19-9DX by uninhibited liquid-phase fuming nitric acid. Shown in Figures 8 and 9 are corrosion vs time curves for liquid-phase corrosion of 19-9DL and 19-9DX, respectively, at 100, 130, and 160 degrees F. The initial rates of reaction (in mils per year) from these curves are plotted as a function of temperature in Figure 10, which also indicates the marked effect of temperature on the initial corrosion rate. In the least temperature-sensitive case, the increase in reaction rate between 100 and 160 degrees F is more than five-fold. The effect of temperature on gas-phase corrosion was measured in a few cases, and the results are shown in Figures 4 and 6.

In some recent tests[3] the effects of temperature fluctuations on the corrosion of 19-9DL in heat treatment A by inhibited fuming nitric acid were measured. The sample bombs were immersed for 30 days in a temperature bath with the temperature sinusoidally fluctuating between 70 and 160 degrees F in a 12-hour period. These data showed that inhibition was not adversely affected by such diurnal temperature fluctuations as might be encountered during storage in the field.

Corrosion of Welded Metal Specimens

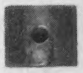
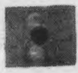
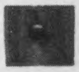
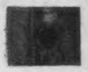
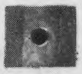
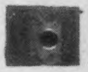
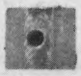
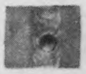
There are, generally, three effects which must be taken into account in the corrosion testing of welded samples: (1) the corrosion rates of the materials involved, (2) the effect of changes in the composition of the deposited weld metal during the welding process which develops a composition gradient across the weld-parent metal interface (thus an electrolytic cell is set up in which the least noble of the ma-

Type of Heat Treatment	Phase to Which Sample Was Exposed	HF Added to FNA (wt %)	Welding-Wire Material								
			19-9WX (Type 2)			19-9DL			19-9WX (Type 1)		
			Extent of Corrosion[a]		Corrosion Rate[b]	Extent of Corrosion[a]		Corrosion Rate[b]	Extent of Corrosion[a]		Corrosion Rate[b]
A	Liquid	0.6	0.05		1.0	0.04		0.9	0.03		0.7
		0	2.5		60	2.1		52	2.2		55
	Gas	0.6	0.03		0.7	0.03		0.7	0.02		0.5
		0	2.8		69	0.71		17	1.6		39
B	Liquid	0.6	0.03		0.7	0.04		0.9	0.04		0.9
		0	2.5		62	2.6		64	2.7		66
	Gas	0.6	0.01		0.3	0.01		0.3	0.02		0.5
		0	0.57		14	0.75		18	1.1		26

[a] Extent of corrosion (mils) was determined by measuring weight loss of sample of known area and density. Local attack near weld is appraised visually.

[b] Corrosion rate (mils/yr) was calculated by dividing depth of corrosion by storage time expressed in years (365 days/yr).

Figure 12—Samples of welded 19-9DX steel exposed to fuming nitric acid for 15 days at 130 F.

Type of Heat Treatment	Phase to Which Sample Was Exposed	HF Added to FNA (wt %)	Welding-Wire Material								
			19-9WX (Type 2)			19-9DL			19-9WX (Type 1)		
			Extent of Corrosion[a]		Corrosion Rate[b]	Extent of Corrosion[a]		Corrosion Rate[b]	Extent of Corrosion[a]		Corrosion Rate[b]
A	Liquid	0.6	0.04		0.9	0.05		1.0	0.02		0.5
		0	3.0		74	3.0		74	3.7		90
	Gas	0.6	0.01		0.3	0.01		0.3	0.01		0.3
		0	0.50		12	0.74		18	0.56		14

[a] Extent of corrosion (mils) was determined by measuring weight loss of sample of known area and density. Local attack near weld is appraised visually.

[b] Corrosion rate (mils/yr) was calculated by dividing depth of corrosion by storage time expressed in years (365 days/yr).

Figure 13—Samples of welded AISI 321 steel exposed to fuming nitric acid for 15 days at 130 F.

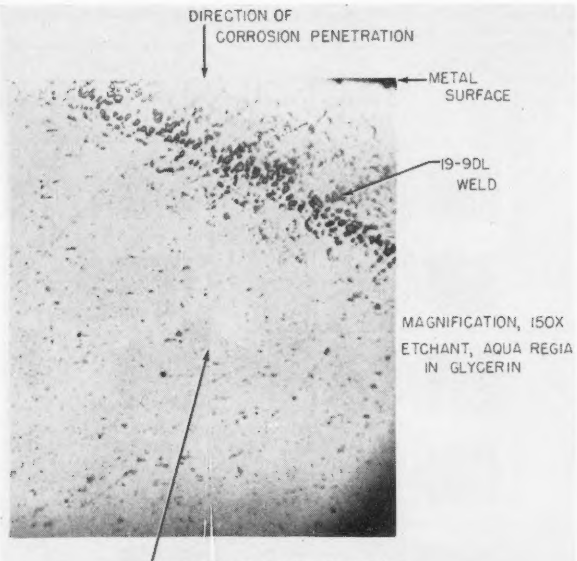


Figure 14—Photomicrograph of 19-9DL weld and 19-9DL adjacent area exposed to inhibited liquid-phase fuming nitric acid with no intergranular corrosion. Actual magnification of photograph after reduction for reproduction purposes is 75X.

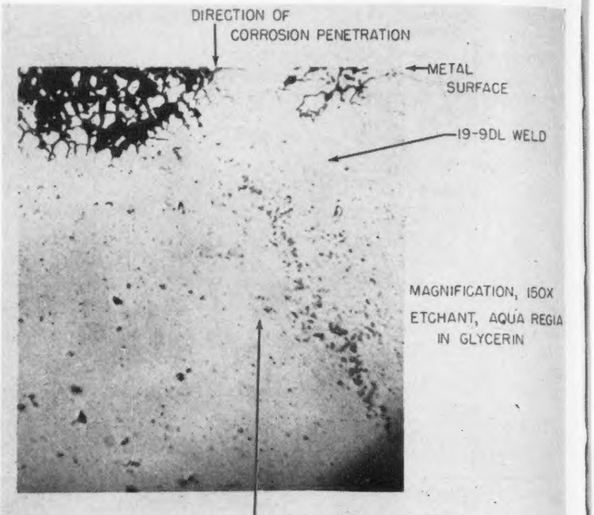


Figure 15—Photomicrograph of 19-9DL weld and 19-9DL adjacent area exposed to uninhibited liquid-phase fuming nitric acid with resulting intergranular corrosion. Actual magnification of photograph after reduction for reproduction purposes is 68X.

terials is sacrificed), and (3) the effect of heating the weld-parent metal junction during the welding process, thus rendering the area adjacent to the weld susceptible to intergranular attack. In order to evaluate the variables mentioned, samples of 19-9DL, 19-9DX, and AISI 321 stainless steels welded with three different welding wires were tested.

The inhibiting effect of HF on corrosion of various welded samples is visually evident from Figures 11 through 13. Corrosion data presented in these figures are based on over-all measurements and therefore do not quantitatively reflect local effects near the weld. Welded samples of 19-9DL and 19-9DX (in both the annealed and the work-hardened conditions) and welded samples of steel 321 showed complete passivation over the surface of the metal including the weld. No signs of intergranular attack adjacent to the weld occurred when sample was exposed either to inhibited gas-phase or to inhibited liquid-phase fuming nitric acid. This can be seen in the photomicrograph of Figure 14 for exposure of 19-9DL welded with 19-9DL to inhibited liquid-phase fuming nitric acid for 30 days at 130 degrees F. Evidence of intergranular corrosion is seen in the case of an identical sample exposed under similar conditions to uninhibited acid as shown in the photomicrograph of Figure 15. With inhibited acid, 19-9DX or 19-9DL welding wires appear to give very corrosion-resistant welds.

Conclusions

From the data presented, it appears that if about 0.6 weight percent HF is added to thermally stable fuming nitric acid containing about 13 weight percent NO_2 and 3 weight percent H_2O, marked passivation against corrosive attack results in welded and unwelded samples of 19-9DL and 19-9DX in both the annealed and the work-hardened condition. One precaution, however, must be observed: The sample should not have previously undergone pitting corrosion, for in this state aggravated corrosion occurs with HF-inhibited acid.

Otherwise, 19-9DL and 19-9DX are suitable materials to be used in contact with HF-inhibited liquid or gaseous fuming nitric acid for periods of at least one month at a steady temperature as high as 160 degrees F or with a fluctuating temperature between 70 and 160 degrees F.

Acknowledgment

The authors thank the Department of the Army, Ordnance Corps, for permission to publish this paper. The authors also express their appreciation to the members of the staff of the Jet Propulsion Laboratory for their assistance and advice.

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2. H. H. Uhlig. Corrosion Handbook. John Wiley and Sons, New York, 1948.
3. David M. Mason, Lois L. Taylor, and John B. Rittenhouse. Inhibiting Effect of Hydrofluoric Acid in Fuming Nitric Acid on Liquid and Gas-Phase Corrosion of Several Metals. Submitted to *Corrosion*.

Corrosion by Low-Pressure Geothermal Steam★

By T. MARSHALL(1) and A. J. HUGILL(2)

Abstract

Corrosion tests in geothermal steam contaminated with chlorides, hydrogen sulfide and carbon dioxide are described, detailed results being given for a range of common engineering alloys.

Most engineering alloys proved moderately susceptible to steam corrosion. Titanium and austenitic stainless steels (especially molybdenum-bearing varieties) were highly resistant. Stress-corrosion cracking occurred in hardened 13 Cr stainless steel, hardened low-alloy steels, one grade of austenitic stainless steel and aluminum bronze.

Physical and chemical factors influencing corrosion by the geothermal steam are discussed. **4.6.2**

Introduction

THE BELT of thermally-active country extending northeast from the Ruapehu-Ngauruhoe-Tongariro volcano group to the coast of the North Island, New Zealand, contains numerous local areas of "hot ground" noted for spectacular thermal and geyser activity. The largest area of surface activity, at Rotorua, covers several square miles. The belt itself is approximately 100 miles long and some 20 miles wide at its widest point.

For many years local residents have, by means of shallow boreholes, tapped hot ground water and occasionally steam (the so-called geothermal steam) for household and other small-scale uses. Only recently, however, has attention been focused on possible large-scale exploitation of these natural heat supplies. Realization of the commercial possibilities stemmed mainly from the successful exploitation of geothermal steam for power production at Larderello, Italy.[1]

In 1949 the New Zealand Government initiated a borehole-prospecting program at Wairakei to assess the potentialities of geothermal heat for commercial uses, particularly electric power production. Two government departments, the Ministry of Works and the Department of Scientific and Industrial Research, carried out this work. The latter department was responsible for geological, chemical and physical investigations, while the Ministry of Works did the engineering development including the drilling of boreholes, measurement of bore outputs, measurement of temperatures, etc.

To date, 33 boreholes have been drilled in an area measuring roughly one square mile. The majority of the boreholes discharged a mixture of steam and water, with no evidence of significant diminution of output during the ensuing period (see Figure 1).

Bores having diameters ranging from 4 to 8 inches have been drilled to depths ranging up to 3,200 feet. All but a few of these bores yielded steam. The maximum output obtained from a single bore (8-inch diameter, at 120 psig wellhead pressure) was 103,000 pounds per hour of steam and 450,000 pounds per hour of water (equivalent to an approximate available power output of 8000 kw.)

When first blown, the bores usually discharge large quantities of debris (mud, sand, stones, etc.) but after a few days' operation this debris diminishes to negligible quantities of very fine mud entrained in the steam. The discharge bore fluid then consists essentially of a two-phase mixture of water and steam, a ratio of four pounds of water to one pound of steam being typical. The water contains significant quantities of dissolved salt and silica, and the steam is contaminated mainly by H_2S and CO_2.

Maximum wellhead pressures up to 420 psig have been experienced, but, as pressure varies inversely with output, high operating pressures are not necessarily advantageous. It is probable that 100-150 psig will be the optimum pressure range for commercial operation. Apparently the energy reservoir being tapped is underground water at high temperature (about 490 F) under hydrostatic pressure exceeding 600 psig. When this water rises to the surface in bores, release of the pressure allows it to flash to the steam/water mixture discharged.

Estimates based on utilization of the steam in turbo-generators indicate a potential available power

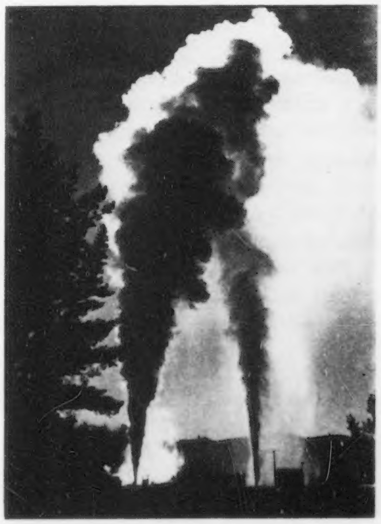

Figure 1—Discharging steam bores at Wairakei.

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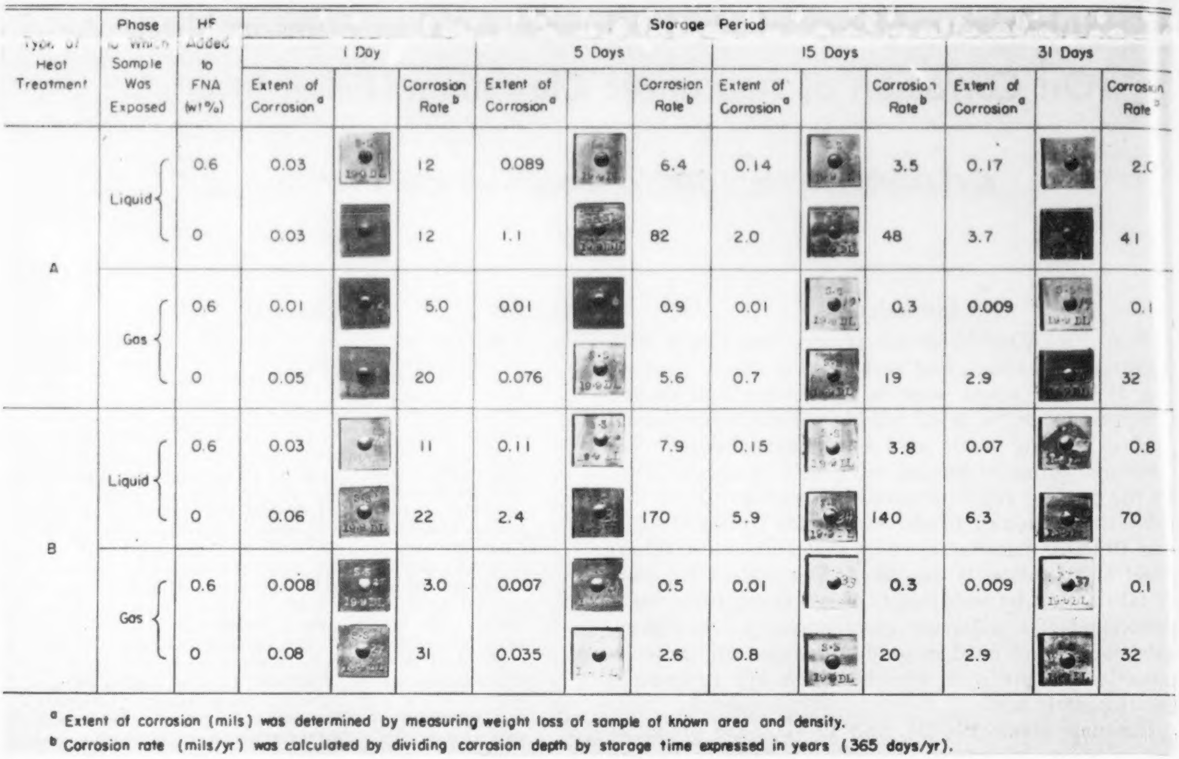

Type of Heat Treatment	Phase to Which Sample Was Exposed	HF Added to FNA (wt%)	1 Day: Extent of Corrosion[a]	1 Day: Corrosion Rate[b]	5 Days: Extent of Corrosion[a]	5 Days: Corrosion Rate[b]	15 Days: Extent of Corrosion[a]	15 Days: Corrosion Rate[b]	31 Days: Extent of Corrosion[a]	31 Days: Corrosion Rate[b]
A	Liquid	0.6	0.03	12	0.089	6.4	0.14	3.5	0.17	2.
		0	0.03	12	1.1	82	2.0	48	3.7	41
	Gas	0.6	0.01	5.0	0.01	0.9	0.01	0.3	0.009	0.1
		0	0.05	20	0.076	5.6	0.7	19	2.9	32
B	Liquid	0.6	0.03	11	0.11	7.9	0.15	3.8	0.07	0.8
		0	0.06	22	2.4	170	5.9	140	6.3	70
	Gas	0.6	0.008	3.0	0.007	0.5	0.01	0.3	0.009	0.1
		0	0.08	31	0.035	2.6	0.8	20	2.9	32

[a] Extent of corrosion (mils) was determined by measuring weight loss of sample of known area and density.
[b] Corrosion rate (mils/yr) was calculated by dividing corrosion depth by storage time expressed in years (365 days/yr).

Figure 1—Samples of Uniloy 19-9DL steel exposed to fuming nitric acid at 130 F.

TABLE 1—Chemical Analyses of Steels Tested

ELEMENT	COMPOSITION OF ELEMENT (Wt. %)[1]									
	19-9DL AMS5526[2,3]	19-9DX AMS5538[2,3]	AISI 321[2]	Unwelded Samples		Welded Samples		Weld Metal		
									19-9WX	
				19-9DL	19-9DX	19-9DL	19-9DX	19-9DL	Type 1	Type 2
Carbon	0.28 to 35	0.28 to 35	0.10 max.	0.29	0.35	0.34	0.32	0.08	0.12	0.14
Manganese	0.75 to 1.50	0.75 to 1.50	2.00 max.	....	....	....	....	....	....	....
Silicon	0.30 to 0.80	0.30 to 0.80	1.00 max.	....	....	....	....	....	....	....
Phosphorus	0.040 max.	0.040 max.	0.040 max.	....	....	....	....	....	....	....
Sulfur	0.030 max.	0.030 max.	0.030 max.	....	....	....	....	....	....	....
Chromium	18.00 to 21.00	18.00 to 21.00	17.00 to 19.00	18.19	18.34	18.55	18.23	21.40	20.66	21.46
Nickel	8.00 to 11.00	8.00 to 11.00	8.00 to 11.00	9.11	9.10	8.85	9.84	8.64	9.01	98.82
Molybdenum	1.00 to 1.75	1.25 to 2.00	....	1.05	1.39	1.43	1.33	0.51	0.52	0.48
Tungsten	1.00 to 1.75	1.00 to 1.75	....	1.50	1.00	1.51	1.27	1.32	2.14	0.99
Niobium and tantalum	0.25 to 0.60	....	....	0.60	0.40	0.36	nil	1.29	0.45	1.17
Titanium	0.10 to 0.35	0.40 to 0.75	min of 5 x wt % C	0.15	0.60	0.15	0.44	0.27	nil	nil
Copper	0.50 max.	0.50 max.	....	....	....	....	....	....	....	....

[1] Dashes indicate that no analysis was made or given.
[2] These analyses were provided by the manufacturer and refer to average steels. The other analyses were made on the actual steel samples used in this investigation.
[3] These steels meet the Aeronautical Material Specifications (AMS).

nitric acid, that a tenacious precipitate of aluminum fluoride forms on the surface of the metal, protecting it from corrosive attack. In the case of stainless steels the chemical nature of the passivating coating has not been definitely established although there is evidence that either chromium or nickel fluoride (or both), when formed on the surface of the metal, is responsible for the passivation process. Because of the solubility mechanism for the passivation process, a coating which forms on a metal dissolves if the metal is exposed to a fresh sample of fuming nitric acid. Since hydrofluoric acid is extremely volatile, storage vessels should not be opened unnecessarily, thus risking the loss of hydrofluoric acid and the removal of the passivating layer.

Methods and Materials

In studying the extent of corrosion of samples the weight-loss method was used. The apparatus used is described in detail elsewhere.[3] Small square samples were placed on a Teflon(5) rod and held in a given position by means of a tight fit between the rod and a hole in the middle of the sample. The

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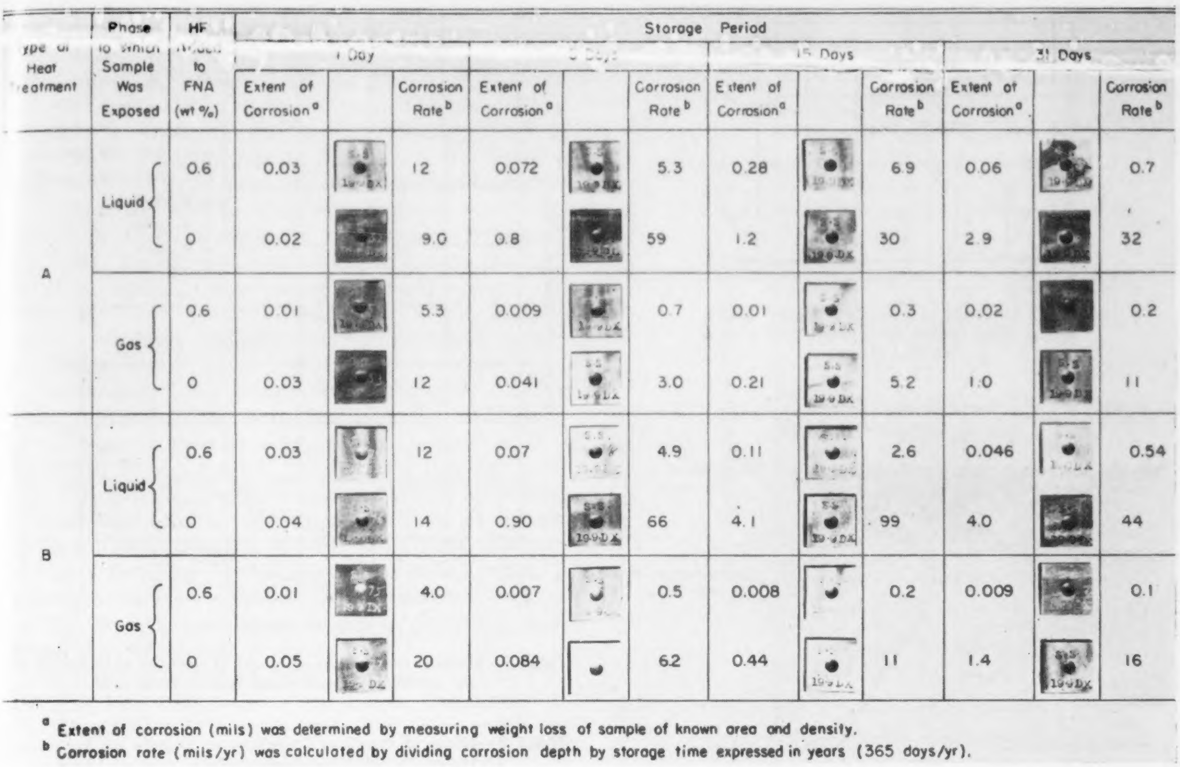
(5) A solid fluorinated ethylene polymer very resistant to fuming nitric acid and manufactured by du Pont de Nemours Co.



Type of Heat Treatment	Phase to Which Sample Was Exposed	HF Added to FNA (wt %)	Storage Period							
			1 Day		5 Days		15 Days		31 Days	
			Extent of Corrosion[a]	Corrosion Rate[b]	Extent of Corrosion[a]	Corrosion Rate[b]	Extent of Corrosion[a]	Corrosion Rate[b]	Extent of Corrosion[a]	Corrosion Rate[b]
A	Liquid	0.6	0.03	12	0.072	5.3	0.28	6.9	0.06	0.7
		0	0.02	9.0	0.8	59	1.2	30	2.9	32
	Gas	0.6	0.01	5.3	0.009	0.7	0.01	0.3	0.02	0.2
		0	0.03	12	0.041	3.0	0.21	5.2	1.0	11
B	Liquid	0.6	0.03	12	0.07	4.9	0.11	2.6	0.046	0.54
		0	0.04	14	0.90	66	4.1	99	4.0	44
	Gas	0.6	0.01	4.0	0.007	0.5	0.008	0.2	0.009	0.1
		0	0.05	20	0.084	62	0.44	11	1.4	16

[a] Extent of corrosion (mils) was determined by measuring weight loss of sample of known area and density.

[b] Corrosion rate (mils/yr) was calculated by dividing corrosion depth by storage time expressed in years (365 days/yr).

Figure 2—Samples of Uniloy 19-9DX steel exposed to fuming nitric acid at 130 F.

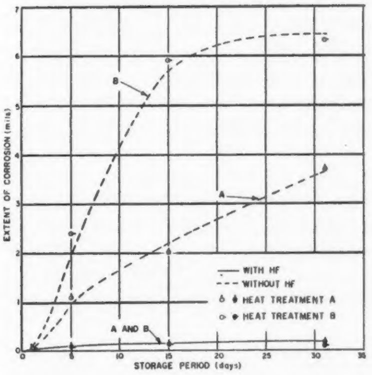


Figure 3—Extent of corrosion of Uniloy 19-9DL by liquid-phase fuming nitric acid at 130 F as a function of time.

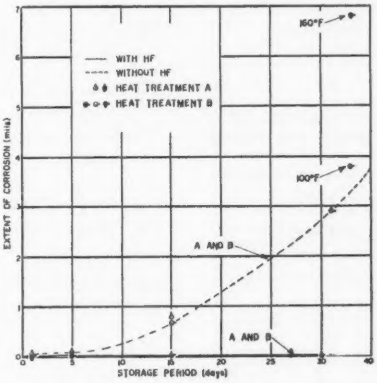


Figure 4—Extent of corrosion of Uniloy 19-9DL by gas-phase fuming nitric acid at 130 F as a function of time.

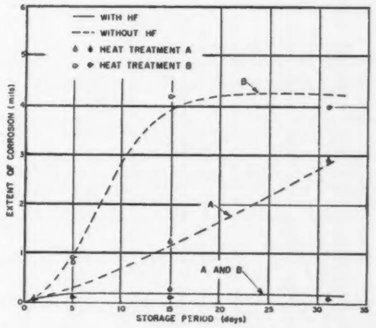


Figure 5—Extent of corrosion of Uniloy 19-9DX by liquid-phase fuming nitric acid at 130 F as a function of time.

samples were then placed in a Teflon-lined aluminum 61S-T6 vessel which was provided with a pressure-tight closure. The Teflon liner had a 1.0 inch inside diameter and was 5.0 inches deep. The vessel was half-filled with fuming nitric acid. Samples on the bottom of the rod thus were exposed to liquid phase, and samples on top of the rod were exposed to gas phase. The ratio of the surface of metal exposed to the volume of acid in the liquid phase as well as in the gas phase was about 1.4 sq in/cu in. The vessels were completely immersed in a constant-temperature water bath maintained within 0.2 degree F of the desired temperature in the range 100 to 160 degrees F.

TABLE 2—Chemical Composition of Fuming Nitric Acid Samples

Component	Composition (Wt. %)	
	Of Inhibited Acid	Of Uninhibited Acid
HNO_3	82.8	84.4
NO_2	13.4	13.1
H_2O	3.2	2.5
HF	0.6	0

After the storage period the samples were removed, washed, and dried. Next the surface of the metal was rubbed with an eraser to remove mechanically as much nonmetallic coating as possible. Each sample was then weighed, and the weight loss

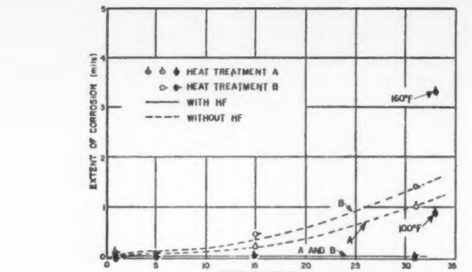


Figure 6—Extent of corrosion of Uniloy 19-9DX by gas-phase fuming nitric acid at 130 F as a function of time.

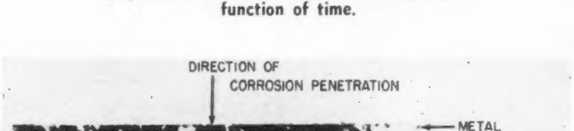

DIRECTION OF CORROSION PENETRATION
METAL SURFACE
MAGNIFICATION, 150X
ETCHANT, NONE
INTERGRANULARLY CORRODED AREA
UNCORRODED AREA

Figure 7—Photomicrograph of Uniloy 19-9DL intergranularly corroded by unihibited liquid-phase fuming nitric acid. Actual magnification of photograph after reduction for reproduction purposes is 53X.

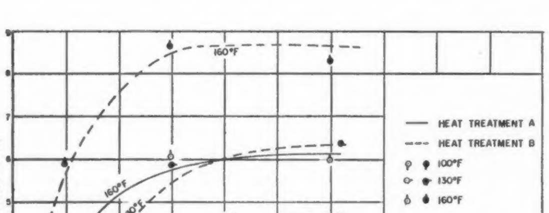


Figure 8—Effect of temperature on extent of corrosion of Uniloy 19-9DL by unihibited liquid-phase fuming nitric acid.

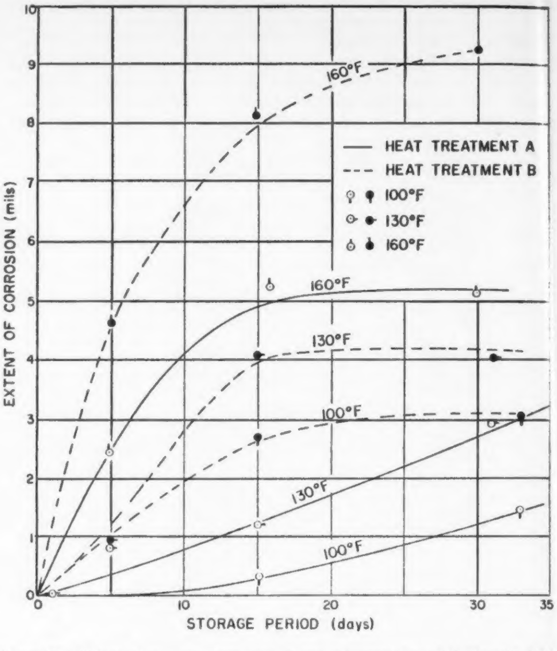


Figure 9—Effect of temperature on extent of corrosion of Uniloy 19-9DX by uninhibited liquid-phase fuming nitric acid.

TABLE 3—Effect of Previous Corrosion of Sample on Subsequent Corrosion by Inhibited Fuming Nitric Acid at 130 F

ALLOY[1]	EXTENT OF CORROSION (mils)	
	Samples in Uninhibited Fuming Nitric Acid[2] (Test 1)	Samples from Test 1 in Inhibited Fuming Nitric Acid[2] (Test 2)
19-9DL	10.0 to 10.2	19 to 21
19-9DX	0.58 to 0.55	3.9 to 4.0

[1] Work-hardened at 1200 F and stress-relieved at 1200 F, identified as heat treatment B.

[2] Samples were exposed to liquid-phase fuming nitric acid for 15 days.

due to corrosion was determined. This weight loss, divided by the product of the exposed area and the density of the sample, was assumed to give the extent of corrosion.

Chemical analysis of the specific steels and the welding wires tested is shown in Table 1. Fuming nitric acid of the initial composition given in Table 2 was used in these tests. Since acid of this composition is stable with respect to thermal decomposition,[1] changes of composition were due mainly to the corrosion process. In the most severe case of corrosion the NO_2 content of the acid after storage had increased by about 7.0 weight percent absolute. In cases in which passivation occurred, the composition of the acid was very slightly altered during storage.

Results

Corrosion of Unwelded Metal Specimens

1. Inhibiting Effect of HF on Corrosion Process. The results of corrosion tests at 130 degrees F on Uniloy 19-9DL and 19-9DX are shown in Figures 1 and 2, respectively, where actual photographs of samples after exposure to liquid- and gas-phase fuming nitric acid are included. Both the extent and the rate of corrosion are indicated in these figures. The inhibiting effect of HF on the corrosion is both visually and numerically evident in Figures 1 and 2 by a comparison, for example, of the data for samples exposed 31 days. In general, the corrosion is less severe on 19-9DX than on 19-9DL for the case of uninhibited liquid- and gas-phase acid. These data are reproduced in Figures 3 through 6 in which the extent of corrosion is plotted vs time for the various sets of conditions. From these figures it is evident that HF markedly inhibits both liquid- and gas-phase corrosion of 19-9DL and 19-9DX. From the slope of the curves for inhibited acid at 30 days it appears that the corrosion rate has approached zero. This behavior is probably due to the formation of a tenacious coating which is impervious to fuming nitric acid and thus protects the metal underneath.

It is noteworthy that in some cases in which inhibition occurred, the extent of corrosion decreased with time. This anomaly probably is due to the fact that it is impossible to remove the passivating layer completely; thus the indicated weight of uncorroded metal is too high, and the extent of corrosion correspondingly low.

It is evident from comparisons of Figure 3 with Figure 4 and Figure 5 with Figure 6 that in 31 days the gas-phase corrosion is less severe than the liquid-phase corrosion for both 19-9DL and 19-9DX with both HF-inhibited and uninhibited acid. However, the corrosion-time curves for uninhibited gas-phase acid are usually concave upward at 30 days, whereas the corresponding liquid-phase curves are usually concave downward. Thus at greater periods of time than 30 days the extent of gas-phase corrosion may exceed that of the liquid phase.

It appears in cases of heat treatment B (see Figures 3 and 5) that without inhibition the corrosion rate after 30 days becomes quite low. This behavior is not understood although changes in composition of the acid resulting from the corrosion process for this period of storage (in which case the H_2O and NO_2 will have increased greatly) may partly explain the behavior. It should be pointed out, however, that particularly in heat treatment B the alloys are susceptible to intergranular corrosion, and the over-all corrosion displayed in Figures 3 and 5 do not reflect the local severity of attack. Shown in Figure 7 is a photomicrograph displaying this type of corrosion for a sample of 19-9DL in heat treatment A exposed to uninhibited liquid-phase fuming nitric acid for 30 days at 130 degrees F. Accompanying this type of corrosion is pitting of the samples; the extent of corrosion based on over-all behavior may not reflect the severity of corrosion locally at pitted areas. In acid containing 0.6 weight percent HF, intergranular corrosion has not been observed, and corrosion in both gas- and liquid-phase is minimized.

2. Effect of Previous Corrosion of Sample on Inhibition Process. It has been found that when a sample of 19-9DL or 19-9DX has undergone severe corrosion by exposure of uninhibited fuming nitric acid, subsequent exposure to HF-inhibited acid results not in passivation but in extremely severe corrosion. This behavior makes it imperative that, in order to ensure inhibition, the sample be exposed only to HF-inhibited fuming nitric acid from the outset. This effect can be seen in results for test 2 in Table 3, where much more severe corrosion results than would be expected for HF-inhibited fuming nitric acid is shown by a comparison with the data of Figures 1 and 2.

In the fabrication of parts from 19-9DL or 19-9DX it is often desirable to clean the surfaces by pickling. One treatment often used involves a 30-minute pickle in a 30 weight percent aqueous solution of HNO_3 at 60 to 80 degrees F. Subsequent exposure to HF-inhibited fuming nitric acid resulted in passivation. Thus this pickling procedure appears to be suitable.

Another treatment consists of exposure for 45 minutes to 15 weight percent HNO_3 and 2 weight percent HF at 135 degrees F. In this treatment severe pitting of the sample occurred and on subsequent exposure to inhibited fuming nitric acid at 130 degrees F for eight days, indications of severe local

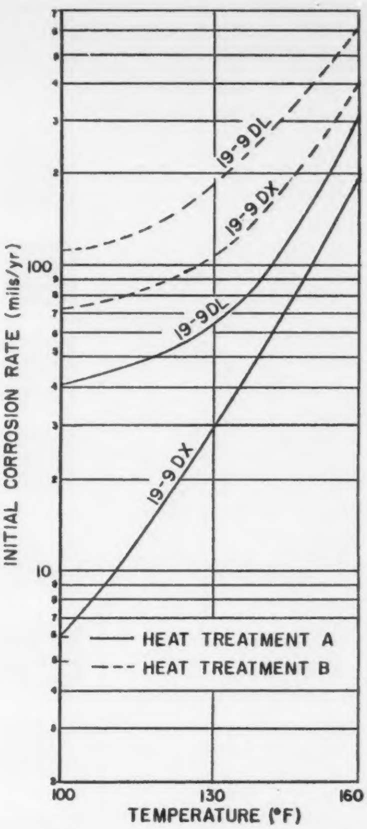


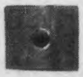
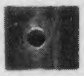
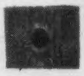
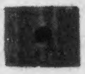
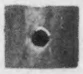
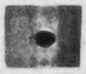
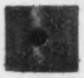
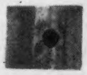
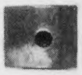
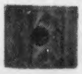
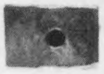
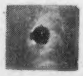
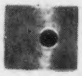
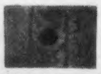
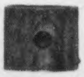
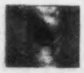
Figure 10—Effect of temperature on initial rate of corrosion of Uniloy 19-9DL and 19-9DX by uninhibited liquid-phase fuming nitric acid.

TABLE 4—Effect of Temperature on Extent of Corrosion of Uniloy 19-9DL and 19-9DX by Uninhibited Liquid-Phase Fuming Nitric Acid

Temperature (Degrees F)	Alloy	Type of Heat Treatment[1]	Extent of Corrosion (mils)		
			At 5 Days	At 15 Days	At 33 Days
100........	19-9DL	A	..	1.5	2.2
		B	..	4.1	4.6 3.8[2]
	19-9DX	A	..	0.3	1.4 0.9[2]
		B	..	2.7	3.0
160........	19-9DL	A	4.0	6.0	6.0
		B	5.9	8.7	8.3 6.8[2]
	19-9DX	A	2.4	5.2	5.1 3.3[2]
		B	4.6	8.1	9.2

[1] Heat treatment A: annealed 2 hours at 1800 F and air-cooled. Heat treatment B: work-hardened and stress-relieved at 1200 F.

[2] Exposure to gas phase.

Type of Heat Treatment	Phase to Which Sample Was Exposed	HF Added to FNA (wt%)	Welding-Wire Material: 19-9WX (Type 2) Extent of Corrosion[a]		Corrosion Rate[b]	19-9DL Extent of Corrosion[a]		Corrosion Rate[b]	19-9WX (Type 1) Extent of Corrosion[a]		Corrosion Rate[b]
A	Liquid	0.6	0.14		3.4	0.05		1.0	0.04		0.9
		0	2.5		60	3.0		72	2.4		58
	Gas	0.6	0.03		0.7	0.03		0.7	0.01		0.3
		0	0.84		20	2.1		51	1.2		30
B	Liquid	0.6	0.13		3.2	0.11		2.7	0.11		2.7
		0	3.0		74	3.2		79	3.2		78
	Gas	0.6	0.02		0.5	0.02		0.5	0.02		0.5
		0	2.2		54	0.99		24	0.79		39

[a] Extent of corrosion (mils) was determined by measuring weight loss of sample of known area and density. Local attack near weld is appraised visually.

[b] Corrosion rate (mils/yr) was calculated by dividing depth of corrosion by storage time expressed in years (365 days/yr).

Figure 11—Samples of welded 19-9DL steel exposed to fuming nitric acid for 15 days at 130 F.

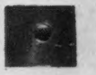
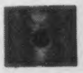
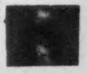
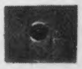
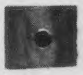
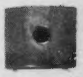
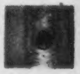
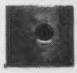
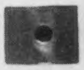
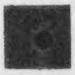
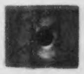
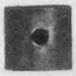
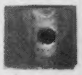
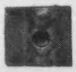
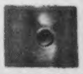
pitting were present. Thus this pickling treatment is not recommended unless the pitted surface is machined thoroughly to remove the pits. Evidently the HF in aqueous nitric acid pickling solutions accelerates the corrosion process and causes pits which are susceptible to aggravated attack on exposures to HF-inhibited fuming nitric acid.

3. Effect of Temperature on Corrosion by Uninhibited Acid. As would be expected from normal reaction-kinetic behavior, an increase in temperature increases the rate of corrosion. Table 4 shows the effect of temperature on extent of corrosion of Uniloy 19-9DL and 19-9DX by uninhibited liquid-phase fuming nitric acid. Shown in Figures 8 and 9 are corrosion vs time curves for liquid-phase corrosion of 19-9DL and 19-9DX, respectively, at 100, 130, and 160 degrees F. The initial rates of reaction (in mils per year) from these curves are plotted as a function of temperature in Figure 10, which also indicates the marked effect of temperature on the initial corrosion rate. In the least temperature-sensitive case, the increase in reaction rate between 100 and 160 degrees F is more than five-fold. The effect of temperature on gas-phase corrosion was measured in a few cases, and the results are shown in Figures 4 and 6.

In some recent tests[3] the effects of temperature fluctuations on the corrosion of 19-9DL in heat treatment A by inhibited fuming nitric acid were measured. The sample bombs were immersed for 30 days in a temperature bath with the temperature sinusoidally fluctuating between 70 and 160 degrees F in a 12-hour period. These data showed that inhibition was not adversely affected by such diurnal temperature fluctuations as might be encountered during storage in the field.

Corrosion of Welded Metal Specimens

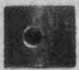
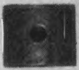
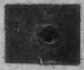
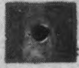
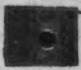
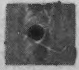
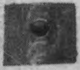
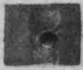
There are, generally, three effects which must be taken into account in the corrosion testing of welded samples: (1) the corrosion rates of the materials involved, (2) the effect of changes in the composition of the deposited weld metal during the welding process which develops a composition gradient across the weld-parent metal interface (thus an electrolytic cell is set up in which the least noble of the ma-

Type of Heat Treatment	Phase to Which Sample Was Exposed	HF Added to FNA (wt %)	Welding-Wire Material								
			19-9WX (Type 2)			19-9DL			19-9WX (Type 1)		
			Extent of Corrosion[a]		Corrosion Rate[b]	Extent of Corrosion[a]		Corrosion Rate[b]	Extent of Corrosion[a]		Corrosion Rate[b]
A	Liquid	0.6	0.05		1.0	0.04		0.9	0.03		0.7
		0	2.5		60	2.1		52	2.2		55
	Gas	0.6	0.03		0.7	0.03		0.7	0.02		0.5
		0	2.8		69	0.71		17	1.6		39
B	Liquid	0.6	0.03		0.7	0.04		0.9	0.04		0.9
		0	2.5		62	2.6		64	2.7		66
	Gas	0.6	0.01		0.3	0.01		0.3	0.02		0.5
		0	0.57		14	0.75		18	1.1		26

[a] Extent of corrosion (mils) was determined by measuring weight loss of sample of known area and density. Local attack near weld is appraised visually.

[b] Corrosion rate (mils/yr) was calculated by dividing depth of corrosion by storage time expressed in years (365 days/yr).

Figure 12—Samples of welded 19-9DX steel exposed to fuming nitric acid for 15 days at 130 F.

Type of Heat Treatment	Phase to Which Sample Was Exposed	HF Added to FNA (wt %)	Welding-Wire Material								
			19-9WX (Type 2)			19-9DL			19-9WX (Type 1)		
			Extent of Corrosion[a]		Corrosion Rate[b]	Extent of Corrosion[a]		Corrosion Rate[b]	Extent of Corrosion[a]		Corrosion Rate[b]
A	Liquid	0.6	0.04		0.9	0.05		1.0	0.02		0.5
		0	3.0		74	3.0		74	3.7		90
	Gas	0.6	0.01		0.3	0.01		0.3	0.01		0.3
		0	0.50		12	0.74		18	0.56		14

[a] Extent of corrosion (mils) was determined by measuring weight loss of sample of known area and density. Local attack near weld is appraised visually.

[b] Corrosion rate (mils/yr) was calculated by dividing depth of corrosion by storage time expressed in years (365 days/yr).

Figure 13—Samples of welded AISI 321 steel exposed to fuming nitric acid for 15 days at 130 F.

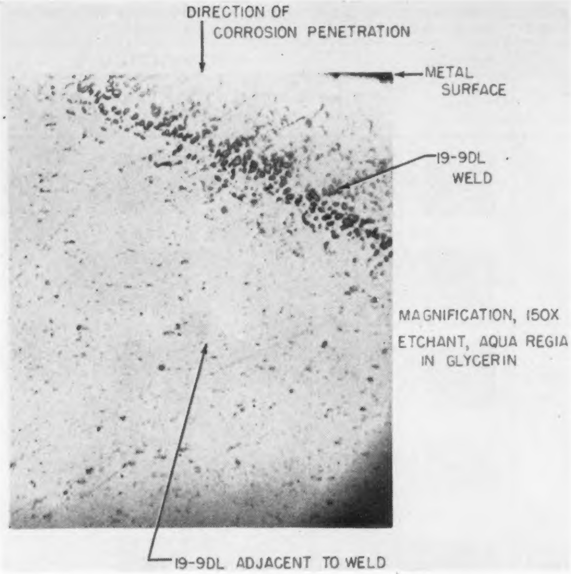


Figure 14—Photomicrograph of 19-9DL weld and 19-9DL adjacent area exposed to inhibited liquid-phase fuming nitric acid with no intergranular corrosion. Actual magnification of photograph after reduction for reproduction purposes is 75X.

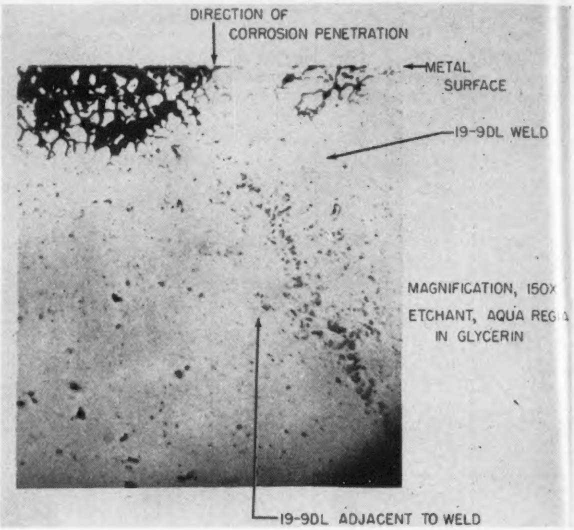


Figure 15—Photomicrograph of 19-9DL weld and 19-9DL adjacent area exposed to uninhibited liquid-phase fuming nitric acid with resulting intergranular corrosion. Actual magnification of photograph after reduction for reproduction purposes is 68X.

terials is sacrificed), and (3) the effect of heating the weld-parent metal junction during the welding process, thus rendering the area adjacent to the weld susceptible to intergranular attack. In order to evaluate the variables mentioned, samples of 19-9DL, 19-9DX, and AISI 321 stainless steels welded with three different welding wires were tested.

The inhibiting effect of HF on corrosion of various welded samples is visually evident from Figures 11 through 13. Corrosion data presented in these figures are based on over-all measurements and therefore do not quantitatively reflect local effects near the weld. Welded samples of 19-9DL and 19-9DX (in both the annealed and the work-hardened conditions) and welded samples of steel 321 showed complete passivation over the surface of the metal including the weld. No signs of intergranular attack adjacent to the weld occurred when sample was exposed either to inhibited gas-phase or to inhibited liquid-phase fuming nitric acid. This can be seen in the photomicrograph of Figure 14 for exposure of 19-9DL welded with 19-9DL to inhibited liquid-phase fuming nitric acid for 30 days at 130 degrees F. Evidence of intergranular corrosion is seen in the case of an identical sample exposed under similar conditions to uninhibited acid as shown in the photomicrograph of Figure 15. With inhibited acid, 19-9DX or 19-9DL welding wires appear to give very corrosion-resistant welds.

Conclusions

From the data presented, it appears that if about 0.6 weight percent HF is added to thermally stable fuming nitric acid containing about 13 weight percent NO_2 and 3 weight percent H_2O, marked passivation against corrosive attack results in welded and unwelded samples of 19-9DL and 19-9DX in both the annealed and the work-hardened condition. One precaution, however, must be observed: The sample should not have previously undergone pitting corrosion, for in this state aggravated corrosion occurs with HF-inhibited acid.

Otherwise, 19-9DL and 19-9DX are suitable materials to be used in contact with HF-inhibited liquid or gaseous fuming nitric acid for periods of at least one month at a steady temperature as high as 160 degrees F or with a fluctuating temperature between 70 and 160 degrees F.

Acknowledgment

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1. David M. Mason, Lois L. Taylor, and Howard F. Keller. Storability of Fuming Nitric Acid. Report No. 20-72, Jet Propulsion Laboratory, Pasadena, December 28, 1953.
2. H. H. Uhlig. Corrosion Handbook. John Wiley and Sons, New York, 1948.
3. David M. Mason, Lois L. Taylor, and John B. Rittenhouse. Inhibiting Effect of Hydrofluoric Acid in Fuming Nitric Acid on Liquid and Gas-Phase Corrosion of Several Metals. Submitted to *Corrosion*.

Corrosion by Low-Pressure Geothermal Steam★

By T. MARSHALL(1) *and A. J. HUGILL*(2)

Abstract

Corrosion tests in geothermal steam contaminated with chlorides, hydrogen sulfide and carbon dioxide are described, detailed results being given for a range of common engineering alloys.

Most engineering alloys proved moderately susceptible to steam corrosion. Titanium and austenitic stainless steels (especially molybdenum-bearing varieties) were highly resistant. Stress-corrosion cracking occurred in hardened 13 Cr stainless steel, hardened low-alloy steels, one grade of austenitic stainless steel and aluminum bronze.

Physical and chemical factors influencing corrosion by the geothermal steam are discussed. **4.6.2**

Introduction

THE BELT of thermally-active country extending northeast from the Ruapehu-Ngauruhoe-Tongariro volcano group to the coast of the North Island, New Zealand, contains numerous local areas of "hot ground" noted for spectacular thermal and geyser activity. The largest area of surface activity, at Rotorua, covers several square miles. The belt itself is approximately 100 miles long and some 20 miles wide at its widest point.

For many years local residents have, by means of shallow boreholes, tapped hot ground water and occasionally steam (the so-called geothermal steam) for household and other small-scale uses. Only recently, however, has attention been focused on possible large-scale exploitation of these natural heat supplies. Realization of the commercial possibilities stemmed mainly from the successful exploitation of geothermal steam for power production at Larderello, Italy.[1]

In 1949 the New Zealand Government initiated a borehole-prospecting program at Wairakei to assess the potentialities of geothermal heat for commercial uses, particularly electric power production. Two government departments, the Ministry of Works and the Department of Scientific and Industrial Research, carried out this work. The latter department was responsible for geological, chemical and physical investigations, while the Ministry of Works did the engineering development including the drilling of boreholes, measurement of bore outputs, measurement of temperatures, etc.

To date, 33 boreholes have been drilled in an area measuring roughly one square mile. The majority of the boreholes discharged a mixture of steam and water, with no evidence of significant diminution of output during the ensuing period (see Figure 1).

Bores having diameters ranging from 4 to 8 inches have been drilled to depths ranging up to 3,200 feet. All but a few of these bores yielded steam. The maximum output obtained from a single bore (8-inch diameter, at 120 psig wellhead pressure) was 103,000 pounds per hour of steam and 450,000 pounds per hour of water (equivalent to an approximate available power output of 8000 kw.)

When first blown, the bores usually discharge large quantities of debris (mud, sand, stones, etc.) but after a few days' operation this debris diminishes to negligible quantities of very fine mud entrained in the steam. The discharge bore fluid then consists essentially of a two-phase mixture of water and steam, a ratio of four pounds of water to one pound of steam being typical. The water contains significant quantities of dissolved salt and silica, and the steam is contaminated mainly by H_2S and CO_2.

Maximum wellhead pressures up to 420 psig have been experienced, but, as pressure varies inversely with output, high operating pressures are not necessarily advantageous. It is probable that 100-150 psig will be the optimum pressure range for commercial operation. Apparently the energy reservoir being tapped is underground water at high temperature (about 490 F) under hydrostatic pressure exceeding 600 psig. When this water rises to the surface in bores, release of the pressure allows it to flash to the steam/water mixture discharged.

Estimates based on utilization of the steam in turbo-generators indicate a potential available power

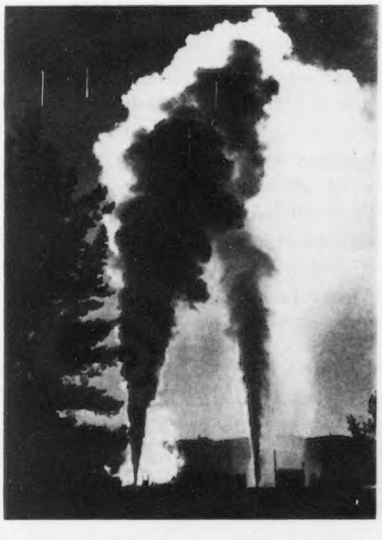

Figure 1—Discharging steam bores at Wairakei.

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output from existing bores at Wairakei, of 40,000 kw as of May 1955.

Thermal measurements[2] over the entire active belt from Lake Taupo to the coast (but excluding the scenic Rotorua area) indicated a total natural escape of heat energy equivalent to an available power output in the order of 250,000 to 480,000 kw. This has been assumed therefore to represent the minimum amount of geothermal power potentially available for commercial utilization. Although little is known of the primary source of heat, it may even be found that a rate of energy extraction far exceeding the natural heat loss can be safely utilized.

From the above description it is seen that the exploratory program has proved the existence of a block of potentially-useful power definitely significant in relation to the country's requirements. Investigations now approach the stage of plant installation of separators, turbines, and generating equipment.

Preliminary examination of equipment used at Wairakei, theoretical considerations, and experience with private boreholes at Rotorua, all suggested that the geothermal steam would be more corrosive than normal boiler-plant steam. In the absence of reliable detailed published information on this subject, preliminary tests were conducted to assess the significance of corrosion by the steam, and to provide corrosion data required by designers of the steam-handling equipment. These tests are described, and results discussed below.

Test Conditions

A geothermal bore (No. 9) whose discharge fluid composition is reasonably representative of all major bores in the Wairakei field, was used for the corrosion tests. The latest analyses[3] from this bore indicate approximate compositions as given in Table 1 for the steam phase (28 weight percent) and the water phase (72 weight percent) of the discharge mixture, after separation in a cyclone operating at 85 psig, as used in the tests.

Concentrations at other pressures can be predicted from thermodynamic data.

Low-Velocity Tests

To simulate various conditions in full-scale plant proposed for utilizing the steam, the corrosion tests were conducted in the following media:

1. Discharge fluid at 15 psig (i.e., the mixture of steam and water discharged directly from No. 9 bore.)
2. Separated steam at 40 psig (i.e., the steam phase separated from the water phase of discharge fluid by a cyclone separator designed according to Stairmand's recommendations[4].) Steam of this type, carrying up to 0.5 weight percent of fine suspended water droplets from the separator, would be supplied to turbines in a full-scale plant.

TABLE 1—Discharge Fluid Composition

Constituent	Concentration in Steam Phase, Parts Per Million by Weight	Concentration in Water Phase, Parts Per Million by Weight
Carbon Dioxide	5,400	5
Hydrogen Sulfide	140	0.5
Ammonia	15	3
Boric Acid	0.6	160
Fluoride (F^-)	0.03	6
Chloride (Cl^-)	Nil	1,500
Sodium	Nil	900
Potassium	Nil	60
Silica	Nil	300

3. Wet separated steam at 10 psig (i.e., separated steam cooled to approximately 10 percent wetness to simulate steam conditions expected at the exhaust end of turbines.)
4. Expanded steam at 0 psig (i.e., separated steam expanded adiabatically to atmospheric pressure, thus providing a small degree of superheat (2.7 F) sufficient to concentrate, but not completely evaporate the water droplets in the steam.) Tests in this medium were aimed at investigating the effect of slight superheat on corrosion.
5. Aerated steam at 3 psig (i.e., separated steam (30 pounds/hour) mixed with air (2 pounds/hour) drawn into a steam line by means of a venturi injector.) Tests in this medium were aimed at investigating the corrosion effects of standby conditions[5] where air contamination of steam can occur.
6. Gas-rich condensate at 160 F and pH 6 (i.e., separated steam condensed and cooled to a temperature low enough to ensure solution of the contaminant gases H_2S (30 ppm) and CO_2 (400 ppm).) Simulation of corrosion conditions in condensers formed the basis of tests in this medium.
7. Gas-free condensate at 212 F and pH 6 (i.e., separated steam condensed at boiling point to preclude solution of the contaminant gases H_2S and CO_2.) The dissolved gas concentrations in this condensate were each less than 1 ppm. Tests in this medium were used to assess the significance of low dissolved gas contents in condensate corrosion.
8. Aerated condensate at 140 F and pH 6 (i.e., aerated steam as in No. 5 above, condensed at a temperature low enough to ensure solution of H_2S (20 ppm) and CO_2 (25 ppm).) These test conditions were included to assess the effect of air contamination on condensate corrosion.
9. Freshwater/condensate mixture at 130 F (i.e., fresh, soft, oxygen-saturated, surface water (pH 7, chloride content 6 ppm) heated by proportional injection of 6 percent of separated steam.) These tests were aimed at simulating the corrosion conditions in jet condensers fed by geothermal steam. The test conditions are a rough approximation only, and are probably more severe than will be encountered in practice, the dissolved gas concentrations and temperature being higher than those

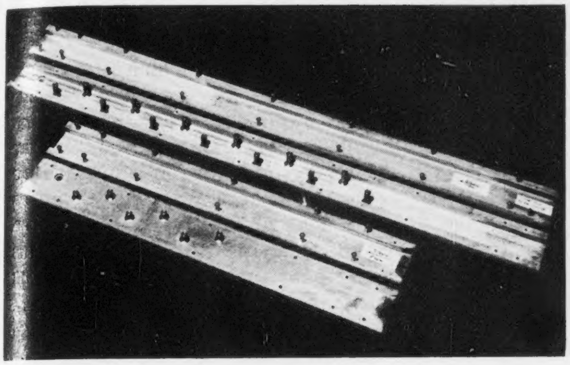

Figure 2—Erosion-corrosion specimens in test channels (opened).

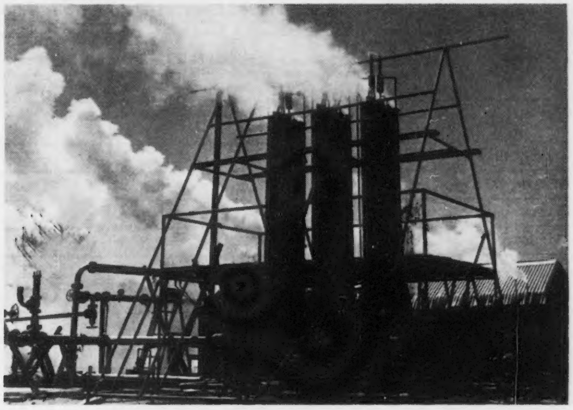

Figure 3—Corrosion testing plant.

TABLE 2—Typical Compositions of Ferrous Alloys Tested

ALLOY	COMPOSITION, PERCENT											Tensile Strengths, Ton/Sq. In.
	C	Si	S	P	Mn	Ni	Cr	Mo	Cu	Cb	Co	
Carbon Steel	0.24 0.20	.07	.04	.01	0.3 0.6				0.2			30 32
Carbon-manganese Steel[1]	0.43	0.3	.01	.01	1.5	0.1			0.2			70
Carbon-molybdenum Steel[1]	0.28	0.2			0.7	0.3	0.2	0.7				37
Manganese-molybdenum Steel[1]	0.37	0.3			1.7			0.3				45
Chrome-molybdenum Steel[1]	0.29	0.2			0.5	0.1	3.1	0.4				65
Nickel Steel[5]	0.15	0.3			0.6	4.7			0.1			40
13 Cr Stainless Steel	.07 .07	0.3 0.2	.03	.04	0.2 0.3		13.3 13.8					45[2] 30
18/8 Cr Ni Stainless Steel	0.1	0.5			0.7	8.9	18.5					40
18/8/1 Cr Ni Cb Stainless Steel	0.11	0.5			0.4	9.5	17.8			1.2		41
18/8/3 Cr Ni Mo Stainless Steel	.05 .06	0.3 .08			0.3 0.4	7.9 8.3	17.6 18.8	3.2 2.8	0.3			46 40
18/12/1 Cr Ni Cb Stainless Steel	0.12	0.8			1.4	12.1	18.5			1.3		41
18/12/2 Cr Ni Mo Stainless Steel	0.10	1.0			0.8	11.5	17.1	2.3				40
35/10 Ni Cr Stainless Steel[3]	0.28				1.4	35.9	10.9					40
'Rex 326' Stainless Steel[4]	0.3	0.7			3.0	17.5	17.2	3.1		2.4	7.1	45
Gray Cast Iron	3.6	2.2	.05	0.4	0.6	0.3	0.1					.
High-silicon Cast Iron	0.7	16.4			1.6							..
'Ni-Resist' Cast Iron	2.9	2.2			1.8	15.5	1.2		6.1			..

[1] Hardened and tempered.
[2] Received as finished steam turbine blades.
[3] Hecla ATV turbine blading alloy.
[4] Firth Vickers, Ltd., gas turbine blading alloy.
[5] Annealed.

in a jet condenser operating efficiently on geothermal turbine-exhaust steam.

10. Standby conditions simulated by exposing specimens alternately to separated steam at 40 psig for 8 hours and to atmospheric air for 16 hours.

In all the above tests, media velocities were kept low enough to avoid erosion-corrosion effects, but high enough to avoid depletion or accumulation of corrosion impurities in the test media.

High Velocity Tests

A further series of erosion-corrosion tests were carried out to assess the influence of velocity on steam corrosion. These tests were conducted in the following media:

1. Separated steam at 60-70 psia and velocity 500-600 fps to simulate the erosion-corrosion conditions affecting inlet-end turbine blading.
2. Wet separated steam at 15-20 psia, 9 percent wetness, and 850-1050 fps, obtained by controlled cooling of separated steam. Tests in this medium were aimed at simulating erosion-corrosion effects on exhaust-end blading of turbines carrying geothermal steam.

TABLE 3—Typical Compositions of Non-Ferrous Alloys Tested

ALLOY	COMPOSITION, PERCENT										Tensile Strength, Ton/Sq. In.
	Si	P	Mn	Ni	Cr	Cu	Sn	Fe	Al	Zn	
Copper						99.9 Min.					16
Silicon Bronze	3.1		0.9			95.7	.04	.05		.07	25
Phosphor Bronze		0.17				94.9	4.9	.03			40
Brass (60/40)						60.8				Rem.	26
Aluminum Bronze[1]	0.2		0.5	0.3		87.5	0.3	3.1	7.5	0.2	30
Monel			1.1	Rem.		29.5		2.1			30
Inconel	0.4		0.2	77.9	13.0			Rem.			35
Nickel			.03	Rem.	.01	0.2		0.2			25
Aluminum (Alcoa 3S)	0.2		1.4			.04		0.5	Rem.		7
Titanium	Commercially-pure Sheet.										50
Nickel-plated steel	Hard nickel plating .010-inch thick.										..
Chromium-plated steel	Hard chrome plating .006-inch thick.										..
Galvanized steel	Hot-dip galvanizing, average coating thickness .0015-inch										..

[1] Cast.
Note: Min. = Minimum, Rem. = Remainder.

Contamination

In all the above tests, except where deliberately added, air contamination of the test media was avoided with the greatest possible care. The necessity for short shutdown periods to inspect and maintain plant prevented complete elimination of air access, but these periods were too short to cause significant errors in corrosion-rate determinations. These standby periods do, however, require consideration in the evaluation of stress-corrosion test results. Similar short standby periods would inevitably occur in full-scale plant operation.

All possible precautions were taken to avoid contamination of test media with corrosion products from upstream equipment in alloys more noble than steel. To this end, stainless steel valves were used wherever possible, though the use of copper-alloy valves could not be entirely avoided.

Test Methods

Average corrosion rates were determined by coupon methods following the ASTM recommended procedure for conducting plant corrosion tests.[6] The recommendations of Uhlig[7] and Champion[8] were followed during cleaning of coupons after exposure, with suitable correction of weight losses for any dissolution of metal during cleaning.

Accuracy limits of plus and minus 30 percent are claimed for the coupon tests results, as representative of the test conditions detailed above.

Stress-corrosion susceptibilities were determined with U-bend specimens as described by Franks, Binder and Brown.[9] The majority of specimens were loaded to maximum fibre stresses slightly beyond the elastic limit. Some additional stress-corrosion tests were carried out on strip specimens with two-point, deadweight loading, similar to test methods described by Sager, Brown and Mears,[10] using various values of maximum stress, up to and beyond the elastic limit. Results of all stress-corrosion tests were based on microscopic examination of tensile-stressed surfaces for cracks.

Erosion-corrosion tests employed metal specimens in the form of $\frac{3}{8}$-inch diameter studs projecting into covered, rectangular, 'Tufnol' channels, down which the steam was passed at controlled velocity (see Figure 2). This test method followed recommendations by turbine designers of the English Electric Company. Micrometer measurement of stud diameters before and after exposure permitted assessment of the depth of erosion-corrosion attack.

Corrosion-testing and steam-handling equipment at No. 9 bore is shown in Figure. 3.

Materials Tested

With the exception of titanium, all materials tested were typical commercial stock of alloys commonly used in steam plant. Compositions are listed in Tables 2 and 3.

Test Results

Results are summarized in Tables 4, 5 and 6.

Table 4 gives average corrosion rates in mils per year, reported to one significant figure and to the number of decimal places consistent with the accuracy limits of the method of determination. For example rates of less than 0.1 mil per year are reported as zero. Occurrence of pitting-type corrosion is indicated by the symbol (P). Most of the rates reported represent averages of a number of determinations.

Table 5 summarizes stress-corrosion test results, the symbol O indicating no fracture of one test piece during the test period, X indicating fracture or cracking of one specimen under test.

Erosion-corrosion test results are summarized in Table 6.

In an additional series of tests, coupons of carbon steel were exposed to separated steam for varying periods of time ranging up to 210 days. Weight losses on the specimens showed an approximately linear relation to time of exposure, with no evidence of decrease in corrosion rate with time.

Discussion

General

The majority of the alloys exposed in these tests showed much higher corrosion rates than those experienced in clean boiler-plant steam under similar conditions. Only molybdenum-bearing austenitic stainless steel and titanium were essentially immune to attack under all test conditions. Behavior of other alloys varied significantly with test conditions and heat treatment, as indicated in Tables 4, 5, and 6. The corrosion resistance of mild steel, though not high, is entirely adequate for long service life in equipment where a moderate corrosion allowance can be incorporated.

TABLE 4—Average Corrosion Rates (Mils Per Year) in Various Media

ALLOY	Expanded Steam, 144-Day Test.	Separated Steam, 144-Day Test.	Wet Separated Steam, 144-Day Test.	Discharge Fluid, 276-Day Test.	Aerated Steam, 144-Day Test.	Gas-Free Condensate, 145-Day Test.	Gas-Rich Condensate, 122-Day Test.	Aerated Condensate, 96-Day Test.	Freshwater/ Condensate Mixture, 67-Day Test.
Carbon Steel	2	6	5	2	20	0.4	3	30	50
Carbon-manganese Steel	1	2	4				3	40	
13 Cr Stainless Steel	0.1(P)	0.3(P)	0.1(P)	0.3(P)	1(P)		0.1(P)	0.9(P)	0.5
18/8 Cr Ni Stainless Steel	0.1(P)	0	0	0(P)	0	0	0	0(P)	
18/8/3 Cr Ni Mo Stainless Steel	0	0	0	0	0	0	0	0	
18/12/2 Cr Ni Mo Stainless Steel	0	0	0		0		0	0	
Gray Cast Iron		3		2	10				90
High Silicon Cast Iron		0.5		2	1				
'Ni-Resist' Cast Iron		1		1	10				
Copper	1	2	3	8	40	0.1	5	40	
Silicon Bronze		3		10	20				
Phosphor Bronze		2		6	9				
Brass	0.2	0.4	0.8	4	40	0	0.2	40	
Aluminum Bronze	0.7	3	3		10		1		
Aluminum	0(P)	0(P)	0(P)	0.1(P)	0(P)	0(P)	0.2	0.5(P)	
Titanium	0	0			0				
Monel	0.5	4	1	3	10	0.1	4	20	
Inconel		0	0	2	80				
Nickel		1		2	8	0.1			
Nickel plated Steel	0.1	1	1		Nickel plating destroyed		2	30	
Chromium plated Steel		0	0	0.2	0				
Galvanized Steel		0(P)		0.2(P)	Zinc coating destroyed	0.1(P)			Zinc coating destroyed

Note: (P) indicates occurrence of pitting type corrosion.

The protective coatings tested all gave moderate to excellent protection in air-free media, but only the hard chrome plating proved protective in aerated steam.

Effect of Steam Conditions

Air in bore fluids greatly accelerated the corrosion of all alloys except aluminum, titanium, austenitic stainless steel, and chromium plating. Avoidance of air ingress and standby corrosion obviously will be important in geothermal steam-handling equipment.

Corrosion rates in separated steam and in wet separated steam are of roughly the same order, whereas rates in expanded steam tend to be lower than those in separated steam. Expanded steam and discharge fluid caused slight but significant pitting of 18/8 Cr Ni stainless steel which resisted this form of attack in other media, and corrosion by discharge fluid was generally more severe than attack by separated steam. These effects show a rough correlation with chloride concentrations in the water phase of test media (see discussion below).

The corrosion-accelerating effect of high steam velocity is clearly shown by results in Table 6. Hardness of an alloy (roughly proportional to tensile strength) does not appear to be the major factor controlling erosion-corrosion resistance. Rate of attack in steam at high velocity does, however, show a strong correlation with corrosion susceptibility in steam at low velocity, the stainless steels exhibiting high resistance to erosion-corrosion (compare with results in Table 4). Table 6 test results suggest that steam velocity will be a factor of more than normal importance in the design of turbines for geothermal steam, and demonstrate the value of austenitic stainless steels for combating erosion-corrosion attack.

It is very difficult, however, to reproduce accurately all relevant plant conditions of pressure, wetness fraction, water droplet size etc. in tests of this nature. Hence precise quantitative evaluation of the significance of erosion-corrosion must await full-scale plant experience.

Condensate Corrosion

Corrosion rates in condensate media were influenced by persistent accumulation of protective grease films (derived from traces of hydrocarbons in the steam) on specimen surfaces; nevertheless they illustrate the major importance of dissolved gases H_2S and CO_2 in accelerating corrosion (compare low corrosion rates in gas-free condensate with high rates in gas-rich condensate). Aerated-condensate test results again illustrate the dramatic corrosion-accelerating effect of air (oxygen) contamination. This effect is confirmed by tests in the freshwater/condensate mixture, where severe attack occurred despite the high degree of dilution of condensate with oxygen-saturated fresh water. In design of condensers for handling geothermal steam, whether of the surface type or the jet type, corrosion control obviously will be an important factor.

TABLE 5—Stress-Corrosion Test Results

ALLOY	Expanded Steam, 96-144 Day Tests.	Separated Steam, 57-177 Day Tests.	Wet Separated Steam, 96-144 Day Tests.	Discharge Fluid, 276 Day Tests.	Aerated Steam, 50-235 Day Tests.	Gas-Free Condensate 145 Day Tests.	Gas-Rich Condensate, 122-138 Day Tests.	Aerated Condensate, 96-122 Day Tests.	Standby Conditions, 59-145 Day Tests.
Carbon Steel	0	0000	0	0	0000	0	0000	0	
Carbon-molybdenum Steel		00			00		00		
Manganese-molybdenum Steel		XX			00		00		
Chrome-molybdenum Steel		XX					XX		
Nickel Steel		XX			0				
13 Cr Stainless Steel, as received[2]	00	0000000	000	0XX	00XXX		0000XX	XX	0000000XXX
13 Cr Stainless Steel, hardened and tempered at 450 C.[3]		0000					XX		XXXX
13 Cr Stainless Steel, hardened and tempered at 750 C.[4]		00			00		00		
13 Cr Stainless Steel, annealed.[5]		0000		0	0		000	0	0000
18/8 Cr Ni Stainless Steel	00	000	00	0	0XX	0	00	00	
18/8/1 Cr Ni Cb Stainless Steel		00			00		00		
18/8/3 Cr Ni Mo Stainless Steel	0	0000	0	0	0000	0	000	0	
18/12/1 Cr Ni Cb Stainless Steel		00			00		00		
18/12/2 Cr Ni Mo Stainless Steel	0	0	0		0				
'Rex 326' Stainless Steel		00			00		00		
35/10 Ni Cr Stainless Steel		00			XX		00		
Copper	0	00	0	0	00	0	0	0	
Silicon Bronze		0		0	0				
Phosphor Bronze		0		0	0				
Brass	0	00	0	0	00	0	0	0	
Aluminum Bronze	0	0	0		X		0	X	
Monel	0	00	0	0	00	0	0	0	
Inconel		00	0	0	00				
Aluminum	0	00	0	0	00	0	0	0	
Titanium	0	000			000		00		

X Denotes cracking of one specimen during test.
0 Denotes absence of cracking on one specimen during test.
[1] Results indeterminate. Fracture of these two specimens could have resulted from air contanination during a short shut-down period.
[2] Specimens machined from steam turbine blades, Brinell hardness 190-225.
[3] Brinell hardness—285.
[4] Brinell hardness—180.
[5] Brinell hardness—150.

Stress-Corrosion Cracking

The stress-corrosion cracking experienced with hardened low-alloy steels, aluminum bronze, and hardened 13 Cr stainless steel is a feature of extreme significance to turbine-plant design.

The absence of stress-corrosion cracking of hardened 13 Cr stainless steel in numerous tests with air-free steam, and its frequent occurrence in aerated steam, provides strong circumstantial evidence that oxygen contamination of the steam is essential for stress-corrosion of this important turbine-blading alloy. This conclusion does not necessarily apply at pressures exceeding 40 psig, to other susceptible alloys, or to condensate media (see discussion below). Numerous tests have demonstrated the immunity of soft 13 Cr stainless steel to this stress-corrosion cracking.

The two isolated cases of cracking of 18/8 Cr Ni stainless steel in aerated steam appear to be related to chloride stress corrosion described by Edeleanu,[11] as discussed below.

Theoretical Aspects

The following working hypothesis has been developed from the above tests and from work by Treseder and others,[12] in an attempt to rationalize the observed and potential influence of steam conditions on corrosion.

Corrosion of Unstressed Alloys. A fundamental hypothesis is first advanced to the effect that, at the low steam temperatures (less than 600 F) currently encountered at Wairakei, significant corrosion of the common engineering alloys would not be experienced in the absence of a liquid water phase (i.e., perfectly dry geothermal steam would be essentially non-corrosive.) This hypothesis is based on the well-known electrochemical theory of corrosion, on normal steam-plant experience, and on data from plants handling in bulk the known contaminants of geothermal steam. The physical characteristics and particularly the chemical composition of the water phase in steam therefore are assumed to be the major corrosion-controlling factors.

TABLE 6—Erosion-Corrosion Test Results

ALLOY	Depth of Erosion-Corrosion Attack Mils. (1 mil = .001 Inch): Separated Steam at 500-600 fps, 50-Day Test	Depth of Erosion-Corrosion Attack Mils. (1 mil = .001 Inch): Wet Separated Steam at 850-1050 fps, 50-Day Test
18/8/1 Cr Ni Cb Stainless Steel	Less than 0.5	0.5
18/12/1 Cr Ni Cb Stainless Steel	Less than 0.5	Less than 0.5
18/8/3 Cr Ni Mo Stainless Steel	Less than 0.5	Less than 0.5
"Rex 326" Stainless Steel	Less than 0.5	Less than 0.5
35/10 Ni Cr Stainless Steel	Less than 0.5	1.5
13 Cr Stainless Steel[1]	Less than 0.5	1
Chrome-Molybdenum Steel	1	6
Carbon-Molybdenum Steel	1.5	10
Manganese-Molybdenum Steel	1.5	10.5
Carbon Steel	1.5	15.5

[1] Hardened and tempered at 750 C, tensile strength 30 ton/sq. in.

Field evidence reviewed by Wilson and Ellis[13] indicates that most of the geothermal bores are tapping a homogeneous underground body of water at an average temperature of 490 F. This suggests that the solid and gaseous impurities of the steam are initially present in solution in the underground water. When this water travels up a bore with concomitant pressure drop and partial flashing to steam, the impurities must tend to distribute themselves between the steam and water phases in accordance with their equilibrium distribution coefficients.

By interpolation of the Ostwald solubility coefficients between 212 F and the critical temperature, Wilson[14] has calculated approximate distribution data for major impurities in the steam. From these data the approximate relationship, for bore 9, between steam pressure and water-phase composition has been calculated for equilibrium conditions, as in Table 7. Adiabatic expansion is assumed during discharge through the bore.

Bore 9 shows slightly irregular behavior and appears to be tapping water mixed with a small amount of steam. Its bottom-hole conditions probably correspond to an intermediate pressure in Table 7.

From this table it is observed that water-phase concentrations of CO_2 and H_2S increase significantly with increase of steam pressure. Work at the National Bureau of Standards[15] has shown that, under air-free conditions, dissolved CO_2 and H_2S accelerate aqueous corrosion, though the effect of their conjoint action at normal or elevated temperatures has not yet been published. Chlorides in solution are well-known corrosion accelerators, and the inhibitive or corrosive effects of silica and other dissolved contaminants of geothermal steam are potentially significant.

Since water-phase concentrations of corrosive impurities increase rapidly with increased steam temperature and pressure, it is seen that corrosion test results at low steam pressures cannot be regarded as valid at high pressures, though variations over the range 0-100 psig should be small.

The above factors, coupled with data from corrosion literature, suggest that corrosion rates should increase with increase in steam pressure. Field experience has partly confirmed this conclusion, and further experimental confirmation is being sought. Also, the test results in Table 4 give some indication of the significance of water-phase composition in controlling corrosion rates. For example expansion of separated steam increases chloride concentration in the water phase, causing pitting of stainless steels; cooling of condensate allows solution of gases which accelerate corrosion.

Corrosion rates in bore fluids, owing to the absence of dissolved oxygen, appear to be controlled by cathodic hydrogen evolution. Such evolution has been observed, in air-free condensate, to occur with concomitant depletion of dissolved H_2S. There is little doubt that the accelerating effect of air on corrosion by bore fluids is due to the depolarizing action of dissolved oxygen, even though it may be present only in a metastable condition (oxygen slowly reacting with H_2S to form free sulfur).

TABLE 7—Effect of Pressure on Equilibrium Water-Phase Composition

Pressure (psig)	Temperature (Degrees F)	Calculated Dryness Fraction of Steam	Approximate Water-Phase Composition, ppm					
			CO_2	H_2S	NH_3	Cl^-	H_3BO_4	SiO_2
0	212	0.38	0.5	0.05	..	1520	190	350
85	327	0.28	5	0.5	3	1500	160	300
200	383	0.23	15	1	..	1400	150	280
400	446	0.15	50	4	..	1300	135	250
600	487	0.10	120	8	..	1200	130	240
800	520	0.05	330	17	..	1120	120	225
1000	545	0.00	1500	40	5	1080	115	215

Stress-Corrosion Cracking. The cracking experienced in these tests bears strong metallographic and environmental similarity to sulfide stress corrosion of hardened carbon steels, nickel steels, and chromium steels as described by Fraser, Treseder[16] and others, and is assumed to be a particular case of the same phenomenon. Test results to date in geothermal media correlate well with oil-field experience of sulfide stress corrosion in that ferrous alloys of tensile strength less than 40 ton/sq in have shown no susceptibility to stress-corrosion cracking.

From experiments under air-free conditions Fraser and Treseder deduced that:

1. Hydrogen sulfide is responsible for the cracking effect.
2. The presence of a liquid water phase is essential for the occurrence of stress corrosion.
3. Increased acidity favors cracking.
4. Chloride ion increases the severity of the environment towards chromium steels.
5. There is greater probability of cracking at low than at high temperature. (From the experimental method used by Fraser and Treseder, this effect may have been explained by the increased H_2S concentration in the test solution at low temperature. Treseder expressed a later opinion[17] that high temperature alone will not prevent cracking).

In addition to the above factors, tests at Wairakei indicate that the presence of dissolved oxygen accelerates cracking of chromium steels.

The above basic requirements for sulfide stress corrosion are found in the steam at Wairakei; hence it may be deduced that the major factors controlling cracking in air-free geothermal fluids are, in order of importance:

1. H_2S concentration in the water phase.
2. CO_2 concentration in the water phase (by its effect on pH at ruling temperature and pressure).
3. Chloride concentration in the water phase.

Variations in composition of the water phase with increased pressure suggest that stress corrosion severity may increase with increase of steam pressure.

Edeleanu[11] demonstrated transcrystalline stress corrosion of austenitic stainless steel in chloride-contaminated steam under conditions where concentration of chlorides in a water phase on the metal surfaces could occur. Absence of this type of stress corrosion in the expanded steam, where similar chloride concentration was present, in contrast to cracking of 18/8 Cr Ni stainless steel experienced in aerated steam, suggests that the presence of oxygen may be an essential factor. The evidence, however, is not conclusive and further investigations are indicated.

Hydrogen Embrittlement. Hydrogen sulfide in solution at temperatures below the atmospheric boiling point is a well known causative agent for hydrogen embrittlement and blistering of steel. Little is known of the effect at higher temperatures.

At Wairakei, hydrogen embrittlement and slight blistering have been experienced in gas-rich condensate and in separated steam. The calculated effect of high pressure increasing the H_2S concentration in the water phase of bore steam again indicates that hydrogen embrittlement may be more active at high than at low pressures, a factor of considerable importance affecting the behavior of bore casings at depth. It also may become important in separating equipment if higher wellhead pressures are obtained in the future.

Miscellaneous. Test results and plant experience to date at Wairakei agree satisfactorily with the above working hypothesis. Extension of the tests to high pressures and to perfectly dry steam media are being planned to provide further useful data and to check the above theories.

Experimental investigations of corrosion-fatigue in the steam have not yet been conducted. It is regarded as axiomatic that any medium causing detectable corrosion of an alloy (especially pitting) will reduce its fatigue life.

Application of Test Results to Plant Design

As a result of these corrosion tests the following precautions in design of full-scale plant to utilize the geothermal steam are at present envisaged:

1. Avoidance of alloys which exhibited poor corrosion resistance in the tests.
2. Use of small turbines with relatively low tip speeds, to permit construction with standard materials in the low-tensile condition, thus avoiding stress-corrosion cracking and minimizing erosion-corrosion of low-pressure blading.
3. Incorporation of corrosion allowances, where necessary, in equipment fabricated from steel, which will be the chief constructional material.
4. Use of protective coating systems where applicable.
5. Removal, wherever possible, of corrosive impurities from the steam system (e.g., by venting off H_2S and CO_2 at heat exchangers.)
6. Use of corrosion-resistant austenitic stainless steels for some critical parts.
7. Application, during plant shutdown, of techniques designed to minimize standby corrosion.

Conclusions

From corrosion tests described above, the following practical conclusions may be drawn:

1. The geothermal steam obtained at Wairakei is definitely more corrosive than clean, boiler-plant steam because of the impurities present (particularly chlorides, H_2S and CO_2). Careful consideration of corrosion factors will be essential in plant design.
2. In the presence of air or oxygen the geothermal fluids become extremely corrosive to most engineering alloys. Thus, in any plant utilizing the steam, measures for avoiding or countering standby corrosion and accidental air ingress will be essential.
3. Sulfide stress-corrosion of susceptible alloys presents a potentially serious hazard for stressed equipment exposed to geothermal fluids. This will be particularly important in turbines.
4. Hydrogen embrittlement of steel requires consideration in the design of steam-handling equipment, and is of potential importance in equipment handling geothermal fluids at high pressure.
5. The projected extension of corrosion and hydrogen-embrittlement tests to high-pressure conditions are of considerable practical and theoretical interest.

Acknowledgments

The authors express their appreciation to other staff members of the Department of Scientific and Industrial Research, particularly to S. H. Wilson, C. A. Roberts, R. Shanton, A. H. Tombs, R. L. Ledger, to engineers of the Ministry of Works, and to several private companies for their valuable assistance and interest in the test program. Thanks are tendered to the Director, Dominion Laboratory, for his permission to publish this paper.

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DISCUSSION

Comments by A. W. Tracy, The American Brass Company, Waterbury, Conn.:

The authors have certainly given data on an unusual corrosion problem. They are to be complimented on the careful work they have done under conditions which do not lend themselves to easy toil.

The results obtained with the copper alloys follow more or less what would be expected in that the corrosion rates are low under conditions where oxygen concentration was low and highest when oxygen was present.

The fact that the corrosion rate of copper was the same as that of brass (Muntz metal) is interesting. In our own laboratory tests, we have found that Muntz metal is much more resistant than copper to sulfide corrosion. In the present instance, it may be that the high corrosion rate of the brass was caused not by sulfide attack but by dezincification, due to the action of the large amount of carbon dioxide in the steam. A description of the condition of specimen after test would give added information. Muntz metal is not generally used for condenser tubes in steam plants today, because of its tendency toward dezincification. Arsenical admiralty or arsenical aluminum brass are most widely used. These alloys are resistant to sulfide corrosion and owing to the presence of small amounts of arsenic are also resistant to dezincification. Information on the resistance of these two alloys under the several conditions of test would be useful.

In the stress-corrosion tests on these copper alloys, only the cast aluminum bronze cracked. We have found that a wrought aluminum bronze, with nominal 7 percent aluminum, 3 percent iron, remainder copper, will stress-corrosion crack under stress. Our tests have shown that a high-zinc alloy, such as Muntz metal, is much more susceptible to stress-corrosion cracking than brasses with 85 percent or more of copper. Moist ammonia in the presence of oxygen is the only agent we know which causes stress-corrosion cracking of copper alloys.

Reply by T. Marshall:

From Table 4 it is seen that, in most of the test environments, the corrosion rate of 60/40 brass was significantly lower than that of copper, a feature amply confirmed by plant experience and confirmatory to Mr. Tracy's laboratory tests. In aerated geothermal media, however, brass and copper corroded at similar rates. Mr. Tracy correctly deduced that this effect of aeration was due to severe dezincification of the brass, layer-type dezincification penetrating to a depth of 0.025 inch in 144 days beneath a compact surface layer of black corrosion products. Under the same conditions, copper produced a loose, voluminous corrosion product in the form of acicular cuprous sulfide crystals (about ⅛ inch long) orientated perpendicular to the corroding surface and forming a non-protective coating.

In air-free media, superficial dezincification of brass (approximately 0.002 inch deep) occurred beneath a tenacious and obviously protective surface film of corrosion products. Copper under air-free conditions formed thin cuprous sulfide surface films which repeatedly flaked away from the underlying metal and were obviously non-protective. The physical behavior of the respective surface films appears to account for the higher corrosion resistance of brass in air-free media.

We cannot, as yet, offer information on the behavior of inhibited brasses in geothermal media since tests are not yet complete. However, inhibition of brasses is expected to confer improved corrosion resistance. The problem of condenser tube dezincification does not yet arise in this field, where ample cooling water supplies and the high concentration of non-condensable gases in the steam favor the use of jet condensers in preference to tubular condensers. Recycling of condensate is, of course, not required.

The stress corrosion cracking of aluminum bronze presents several curious features. The cracking showed marked similarity to sulfide stress corrosion of steels, in that single fractures traversed the entire specimen cross-sections, and did not show the branched, multiple cracking commonly encountered in stress corrosion of copper-base alloys by ammonia. Since ammonium compounds are present in the steam, 'season cracking' of brass would be expected, but has not been encountered. These unusual features present problems for further investigation, which we hope to undertake in the future.

Any discussions of this article not published above will appear in the June, 1957 issue.

Testing Methods and Corrosion Control Measures For Buried Telephone Cable★

By DANIEL R. WERNER

DANIEL R. WERNER is in charge of cable corrosion control engineering, Western Area, American Telephone and Telegraph Company, Kansas City, Missouri. He has been in electrolysis work on telephone cables since 1934. He holds BS and EE degrees from Rose Polytechnic Institute at Terre Haute, Indiana.

Abstract

Most of the thousands of miles of buried telephone cable installed by the Bell System have been placed within the past 10 to 15 years. Although relatively few serious corrosion troubles have been experienced on these cables to date, investigations have indicated that damage due to corrosion on this type of plant may be expected to increase unless special mitigative measures are employed.

The number of miles of cable involved has made desirable the development of special layout records which will serve as a base for recording such field data as potential of cable to reference electrodes, sheath current flow measurements, location of corrosion troubles, etc. One such record developed by the author is described.

The difficulty involved in obtaining access to buried cable at the frequent intervals desirable for measurement of current flow on the cable sheath has led to consideration of other means of testing to more precisely locate areas of current loss and the amount of current discharged to the soil. Testing methods now under field trial by the author are discussed.

Utilization of data obtained by the above methods to determine the probable life of a cable from a corrosion standpoint and for balancing the estimated cost of remedial measures for an expected cable life against the cost of replacing the cable at some future date are also described. 7.7

Introduction

MOST OF the thousands of miles of buried intercity telephone cables now utilized by the Bell System have been placed within the last 10 or 15 years. A description of the various types of buried cables has been given in several papers presented at NACE conferences in the past.[1, 2, 3, 4]

The older types, such as tape armored and wire armored cables, have certain construction features in common. The lead sheath of these cables is first covered by a serving of jute over which is placed the steel tapes or galvanized armor wires. On the outside of the steel tapes or armor wires another serving of jute is placed. These jute servings are impregnated with a preservative compound.

The impregnated jute flooded with asphalt will absorb moisture from the soil. Its resistance will vary depending upon the conductivity of the soil waters (i.e., the amount of ions in the water.)

The steel tapes or galvanized armor wires of the cables mentioned above are bonded to the lead sheath at splice points. The dissimilar metals, combined with the ionized moisture in the impregnated jute, set up a galvanic cell in which the steel tapes or galvanized armor wires act as anodes in the presence of neutral or acid soil waters. The lead sheath thus receives cathodic protection at the expense of the steel tapes or galvanized armor wires. There have been no known failures of the lead sheath of these type cables due to corrosion in non-stray current areas. The steel tapes and armor wires were found, however, to be corroded through in a few instances.

Testing Methods

There are limited locations where contact can be made to intercity buried cables for cable to soil potential measurements. These cables are maintained under gas pressure. Pressure testing valves are generally accessible above the surface of the ground, at marker posts, about every 3000 feet. Contact can be made to the cable at these points. In addition, current flow test points are usually installed as follows:

1. At every splice point (900 to 3000 foot spacing depending upon the size and type of cable) in proximity to railroads equipped with DC signalling.
2. At half mile intervals when the cable route closely parallels electric railways.
3. At one mile intervals, or at three and one half mile intervals depending upon other factors. The one mile or longer interval between test points is general where other structures are not present in the vicinity of the cable route.

   The test point intervals vary to provide test points at pipe line crossings and in areas adjacent to galvanized wire armored cable sections. Experience has shown that current in various amounts will generally be discharged into wire armored sections.

The distance between current flow test points may be such that current pickup and discharge from the cable may occur without definite evidence of such action being indicated by measurements made at the

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★ Submitted for publication March 27, 1956. A paper presented at the Twelfth Annual Conference, National Association of Corrosion Engineers, New York, N. Y., March 12-16, 1956.

TABLE 1—Determination of Current Pickup and Current Loss Areas[1]

TEST	Potential to Roving Half Cell Placed Over Center Line of Structure Being Tested	Potential to Roving Half Cell Placed an Equal Distance Each Side of the Structure Being Tested		Col. (2) Minus Col. (1)	Col. (3) Minus Col. (1)	Col. (4) Plus Col. (5)
		Left	Right			
	(1)	(2)	(3)	(4)	(5)	(6)
1	—.38	—.33	—.32	+.05	+.06	+.11
2	—.38	—.48	—.47	—.1	—.09	—.19
3	—.63	—.58	—.57	+.05	+.06	+.11
4	—.57	—.43	—.68	+.14	—.11	+.03

[1] Analysis of half cell readings was made to determine current pickup and current loss areas when the roving half cell was placed first over the structure being tested then an equal distance of four feet to 25 feet each side of the structure being tested.

Interpretation of Test Results

If Columns (4) and (5) are both positive for any particular test result then current is leaving the structure to the earth.

If Columns (4) and (5) are both negative for any particular test result then current is entering the structure from the earth.

If Columns (4) and (5) are both positive and negative as in Test 4 then cross currents flowing through the earth are of sufficient magnitude to be confusing.

Column (6) is the addition of Columns (4) and (5) and eliminates the confusing effect of cross currents. A positive value indicates current flow from the structure to the earth and negative value indicates current flow to the structure from the earth.

NOTE: The above interpretation of the test results should hold good where the earth resistivity is fairly uniform in a transverse direction to the line of the structure, the earth is virgin soil and does not contain any metal placed by man except the structure being tested. The presence of any other metal such as pipes and discarded cans and the like will disturb the earth gradient and render the analysis difficult or impracticable.

current flow test points. At points of current loss the cable to soil potential may test somewhat more negative but the change in potential may be less than 50 millivolts from that at current pickup points. Cable to soil measurements at the pressure testing valve points may not reveal any significant change in cable to soil potential.

Gradient Tests

The fact that the cable to soil potential may test more negative at current loss areas has led to the development of a method of testing which may be described as Surface Potential Gradient Testing. This method has been used by pipe line people for a number of years. It is based on the voltage drop through the earth, the measurements being made at the surface of the earth. Methods of utilizing these tests on buried intercity cables already have been described.[5]

Table 1 shows how current pickup and current loss areas may be determined from data obtained by these tests and Figure 1 shows some of the circuits that may be used in its application.

Interpretation of Results

The results obtained in Columns (1) and (6) of Table 1 are plotted versus the distance along the structure. The length of the current loss area can then be determined from the resulting graph. Analysis of the graph will also indicate where additional current flow test leads should be installed to determine the amount of current flowing into the current loss area in order to determine the current discharge rate and the probable structure life which will be discussed later.

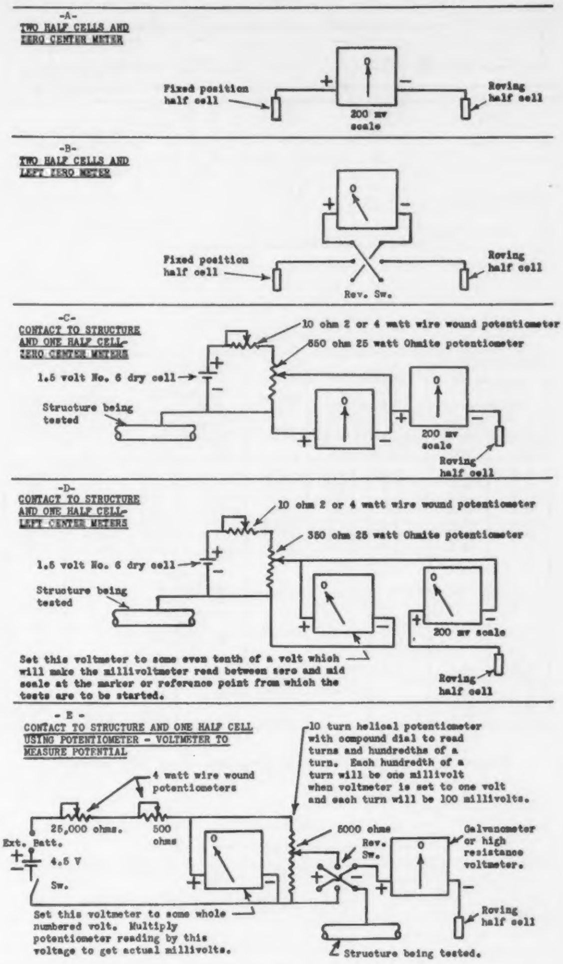
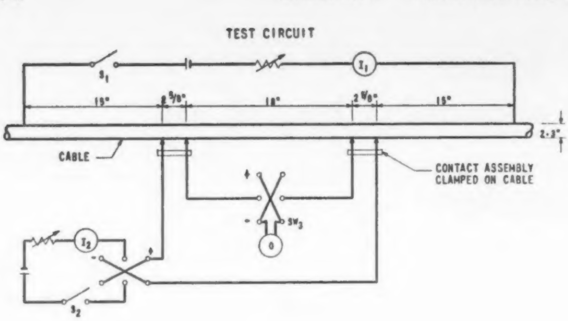

-A-
TWO HALF CELLS AND ZERO CENTER METER
Fixed position half cell
+
−
200 mv scale
Roving half cell
-B-
TWO HALF CELLS AND LEFT ZERO METER
Fixed position half cell
Rev. Sw.
Roving half cell
-C-
CONTACT TO STRUCTURE AND ONE HALF CELL- ZERO CENTER METERS
10 ohm 2 or 4 watt wire wound potentiometer
350 ohm 25 watt Ohmite potentiometer
1.5 volt No. 6 dry cell
Structure being tested
200 mv scale
Roving half cell
-D-
CONTACT TO STRUCTURE AND ONE HALF CELL- LEFT CENTER METERS
10 ohm 2 or 4 watt wire wound potentiometer
350 ohm 25 watt Ohmite potentiometer
1.5 volt No. 6 dry cell
Structure being tested
200 mv scale
Set this voltmeter to some even tenth of a volt which will make the millivoltmeter read between zero and mid scale at the marker or reference point from which the tests are to be started.
Roving half cell
- E -
CONTACT TO STRUCTURE AND ONE HALF CELL USING POTENTIOMETER - VOLTMETER TO MEASURE POTENTIAL
4 watt wire wound potentiometers
10 turn helical potentiometer with compound dial to read turns and hundredths of a turn. Each hundredth of a turn will be one millivolt when voltmeter is set to one volt and each turn will be 100 millivolts.
25,000 ohms.
500 ohms
Ext. Batt.
4.5 V
Sw.
5000 ohms
Rev. Sw.
Galvanometer or high resistance voltmeter.
Set this voltmeter to some whole numbered volt. Multiply potentiometer reading by this voltage to get actual millivolts.
Roving half cell
Structure being tested.

Figure 1—Meter circuits for earth potential gradient testing. Millivoltmeter should be at least 200,000 ohms per volt.

The Surface Potential Gradient testing method is slow and experience has indicated much territory may be covered before any significant possible corrosion condition is revealed. In order to make the method more practicable, there is under development a method of automatically recording the variations in the structure to soil potential on a strip chart. Visible changes in the terrain which might be contributing factors to variations in the structure to soil potential would be noted on the strip chart. Such recordings would be made on a selective basis at first, followed by more general application if it appeared desirable.

Measurement of Current on Structure

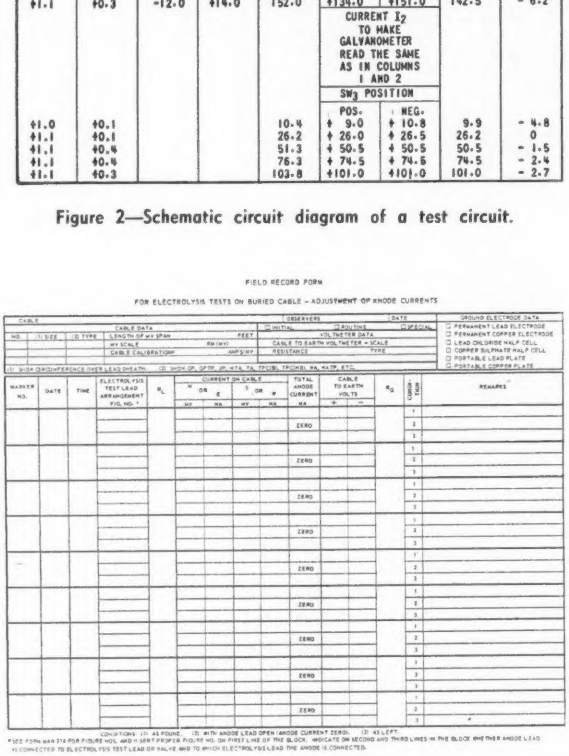
The current flow on a structure at current flow test points can be conveniently determined by the null or zero resistance ammeter method. On buried cables the present standard length of cable bridged for the current flow measurements is 30 feet. At each end of this 30 foot section paired test leads are soldered to the cable and the ends terminated on



TEST RESULTS

CONTACT PONTENTIAL GALVANOMETER LIGHT BEAM DEFLECTION, S_1 AND S_2 OPEN. REVERSING SW. 3 POS.	NEG.	GALVANOMETER LIGHT BEAM DEFLECTION, S_1 CLOSED. REVERSING SW. 3 POS.	NEG.	CURRENT I_1 M.A.	CURRENT I_2 TO MAKE GALVANOMETER READ ZERO. GALVANOMETER SW_3 POSITION POS.	NEG.	AVERAGE CURRENT I_2	PER CENT ERROR
+1.0	+0.1	+ 0.05	+ 1.1	10.4	− 1.5	+ 12.3	6.9	−33.3
+1.1	+0.1	− 1.2"	+ 2.7	26.2	+ 13.8	+ 28.8	21.3	−18.7
+1.1	+0.4	− 3.5	+ 5.0	51.3	+ 38.5	+ 55.0	46.7	− 8.9
+1.1	+0.4	− 5.7	+ 8.2	76.3	+ 61.5	+ 79.5	70.5	− 7.6
+1.1	+0.4	− 8.0	+10.0	103.8	+ 90.0	+107.0	98.5	− 5.1
+1.1	+0.4	−10.0	+11.7	125.0	+111.0	+128.0	119.5	− 4.4
+1.1	+0.3	−12.0	+14.0	152.0	+134.0	+151.0	142.5	− 6.2
					CURRENT I_2 TO MAKE GALVANOMETER READ THE SAME AS IN COLUMNS 1 AND 2 SW_3 POSITION POS.	NEG.		
+1.0	+0.1			10.4	+ 9.0	+ 10.8	9.9	− 4.8
+1.1	+0.1			26.2	+ 26.0	+ 26.5	26.2	0
+1.1	+0.4			51.3	+ 50.5	+ 50.5	50.5	− 1.5
+1.1	+0.4			76.3	+ 74.5	+ 74.6	74.5	− 2.4
+1.1	+0.3			103.8	+101.0	+101.0	101.0	− 2.7

Figure 2—Schematic circuit diagram of a test circuit.



FIELD RECORD FORM

FOR ELECTROLYSIS TESTS ON BURIED CABLE – ADJUSTMENT OF ANODE CURRENTS

CABLE
OBSERVERS
DATE
GROUND ELECTRODE DATA
CABLE DATA
☐ INITIAL ☐ ROUTINE ☐ SPECIAL
NO. (1) SIZE (2) TYPE
LENGTH OF MV SPAN FEET
VOLTMETER DATA
MV SCALE RM (MV)
CABLE TO EARTH VOLTMETER – SCALE
CABLE CALIBRATION AMPS/MV
RESISTANCE TYPE
☐ PERMANENT LEAD ELECTRODE
☐ PERMANENT COPPER ELECTRODE
☐ LEAD CHLORIDE HALF CELL
☐ COPPER SULPHATE HALF CELL
☐ PORTABLE LEAD PLATE
☐ PORTABLE COPPER PLATE
(1) SHOW CIRCUMFERENCE OVER LEAD SHEATH. (2) SHOW CP, CPTP, JP, HTA, TA, TPC(B), TPC(HB), HA, HATP, ETC.

MARKER NO.	DATE	TIME	ELECTROLYSIS TEST LEAD ARRANGEMENT FIG. NO.*	R_L	CURRENT ON CABLE N OR E MV	MA	S OR W MV	MA	TOTAL ANODE CURRENT MA	CABLE TO EARTH VOLTS +	−	R_G	CONDI-TION	REMARKS
													1	
									ZERO				2	
													3	
													1	
									ZERO				2	
													3	
													1	
									ZERO				2	
													3	
													1	
									ZERO				2	
													3	
													1	
									ZERO				2	
													3	
													1	
									ZERO				2	
													3	
													1	
									ZERO				2	
													3	
													1	
									ZERO				2	
													3	
													1	
									ZERO				2	
													3	

CONDITIONS: (1) AS FOUND. (2) WITH ANODE LEAD OPEN (ANODE CURRENT ZERO). (3) AS LEFT.

*SEE FORM MAW 214 FOR FIGURE NOS. AND INSERT PROPER FIGURE NO. ON FIRST LINE OF THE BLOCK. INDICATE ON SECOND AND THIRD LINES IN THE BLOCK WHETHER ANODE LEAD IS CONNECTED TO ELECTROLYSIS TEST LEAD OR VALVE AND TO WHICH ELECTROLYSIS LEAD THE ANODE IS CONNECTED.

Figure 3—Form MAW-213 (field record form for electrolysis tests on buried cable and adjustment of anode currents.)

marker posts. Figure 2 shows a schematic circuit diagram of a test circuit which was used to determine the accuracy of the method when measuring the current flow on 18 inches of cable sheath such as might be available in a manhole. The measurement of currents of a few milliamperes over short lengths of cable sheath is discussed in a paper recently published in *Corrosion.*[6]

In Figure 2, the current I_1 represents the unknown current flowing on the structure which causes a voltage drop measured by the galvanometer. The current I_2 is a known current superimposed on the cable. This current I_2 is varied until the galvanometer reads zero. Under this condition the current I_2 should be exactly the same value as the current I_1.

Thermal potentials produced at contacts appear to have considerable influence on the accuracy of the measurement as indicated in Figure 2. These effects are minimized by obtaining values of the superimposed current I_2, with the galvanometer leads normal and reversed and averaging the two values so obtained, and also by shielding the measuring equipment from the direct rays of the sun.

Cable to Soil Potential Criteria

There are as many different structure to soil potential criteria as there are kinds of metals buried in the soil. When a reference half cell is placed over the center line of a buried structure and out of the raised earth potential field of any cathodic protection installations, satisfactory potentials to some metals might be as shown in the following table:

Kind of Metal Buried in the Soil	Satisfactory Structure to Soil Potential as Measured to a Copper-Copper Sulfate Reference
Copper	—0.25
Lead	—0.78
Steel	—0.85
Galvanizing (Zinc)	—1.05 to —1.1

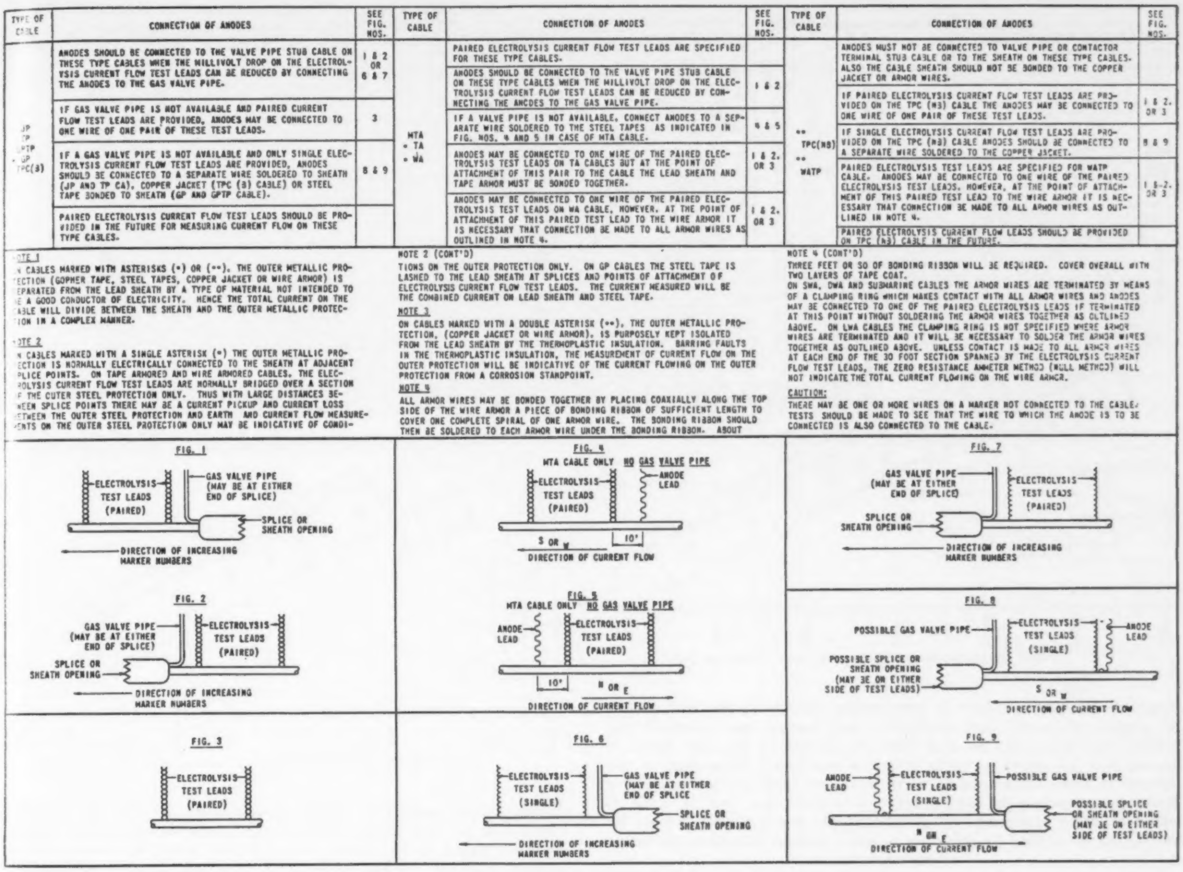
The figures given for copper, lead and steel are considered sufficient to overcome any small galvanic potentials that might exist. The figure given for galvanizing is based on field experience on newly installed cables where the zinc is neither picking up current from or discharging current to the earth.

Zinc, being an amphoteric metal, may be consumed when in an alkaline environment such as may sometimes be produced by the application of cathodic protection. Furthermore the galvanizing on steel armor wires without the application of cathodic protection may be expected to last for only 8 to 10 years. It would appear, therefore, that any considerable reduction in the galvanized steel wire armor to earth potential would be indicative of loss of the galvanizing.

Locating Magnesium Anodes for Cathodic Protection

It has been found that on structures having a high attenuation to cathodic protection currents, the remedial measures must be installed at or very close to the current loss areas. Telephone cables having an outer covering of jute are generally in this category. There appear to be two methods by which cathodic protection using anodes can be applied to correct a current loss condition. The method selected should be governed by the relative attenuation of the natural galvanic currents flowing as compared to the attenuation of any drainage currents which may be applied. The two methods are as follows:

1. In those cases where the natural galvanic currents attenuate at a faster rate than any



TYPE OF CABLE	CONNECTION OF ANODES	SEE FIG. NOS.
JP TP GPTP * GP TPC(B)	ANODES SHOULD BE CONNECTED TO THE VALVE PIPE STUB CABLE ON THESE TYPE CABLES WHEN THE MILLIVOLT DROP ON THE ELECTROLYSIS CURRENT FLOW TEST LEADS CAN BE REDUCED BY CONNECTING THE ANODES TO THE GAS VALVE PIPE.	1 & 2 OR 6 & 7
	IF GAS VALVE PIPE IS NOT AVAILABLE AND PAIRED CURRENT FLOW TEST LEADS ARE PROVIDED, ANODES MAY BE CONNECTED TO ONE WIRE OF ONE PAIR OF THESE TEST LEADS.	3
	IF A GAS VALVE PIPE IS NOT AVAILABLE AND ONLY SINGLE ELECTROLYSIS CURRENT FLOW TEST LEADS ARE PROVIDED, ANODES SHOULD BE CONNECTED TO A SEPARATE WIRE SOLDERED TO SHEATH (JP AND TP CA), COPPER JACKET (TPC (B) CABLE) OR STEEL TAPE BONDED TO SHEATH (GP AND GPTP CABLE).	8 & 9
	PAIRED ELECTROLYSIS CURRENT FLOW TEST LEADS SHOULD BE PROVIDED IN THE FUTURE FOR MEASURING CURRENT FLOW ON THESE TYPE CABLES.	

TYPE OF CABLE	CONNECTION OF ANODES	SEE FIG. NOS.
MTA * TA * WA	PAIRED ELECTROLYSIS CURRENT FLOW TEST LEADS ARE SPECIFIED FOR THESE TYPE CABLES.	
	ANODES SHOULD BE CONNECTED TO THE VALVE PIPE STUB CABLE ON THESE TYPE CABLES WHEN THE MILLIVOLT DROP ON THE ELECTROLYSIS CURRENT FLOW TEST LEADS CAN BE REDUCED BY CONNECTING THE ANODES TO THE GAS VALVE PIPE.	1 & 2
	IF A VALVE PIPE IS NOT AVAILABLE, CONNECT ANODES TO A SEPARATE WIRE SOLDERED TO THE STEEL TAPES AS INDICATED IN FIG. NOS. 4 AND 5 IN CASE OF MTA CABLE.	4 & 5
	ANODES MAY BE CONNECTED TO ONE WIRE OF THE PAIRED ELECTROLYSIS TEST LEADS ON TA CABLES BUT AT THE POINT OF ATTACHMENT OF THIS PAIR TO THE CABLE THE LEAD SHEATH AND TAPE ARMOR MUST BE BONDED TOGETHER.	1 & 2. OR 3
	ANODES MAY BE CONNECTED TO ONE WIRE OF THE PAIRED ELECTROLYSIS TEST LEADS ON WA CABLE, HOWEVER, AT THE POINT OF ATTACHMENT OF THIS PAIRED TEST LEAD TO THE WIRE ARMOR IT IS NECESSARY THAT CONNECTION BE MADE TO ALL ARMOR WIRES AS OUTLINED IN NOTE 4.	1 & 2. OR 3

TYPE OF CABLE	CONNECTION OF ANODES	SEE FIG. NOS.
** TPC(NB) ** WATP	ANODES MUST NOT BE CONNECTED TO VALVE PIPE OR CONTACTOR TERMINAL STUB CABLE OR TO THE SHEATH ON THESE TYPE CABLES. ALSO THE CABLE SHEATH SHOULD NOT BE BONDED TO THE COPPER JACKET OR ARMOR WIRES.	
	IF PAIRED ELECTROLYSIS CURRENT FLOW TEST LEADS ARE PROVIDED ON THE TPC (NB) CABLE THE ANODES MAY BE CONNECTED TO ONE WIRE OF ONE PAIR OF THESE TEST LEADS.	1 & 2. OR 3
	IF SINGLE ELECTROLYSIS CURRENT FLOW TEST LEADS ARE PROVIDED ON THE TPC (NB) CABLE ANODES SHOULD BE CONNECTED TO A SEPARATE WIRE SOLDERED TO THE COPPER JACKET.	8 & 9
	PAIRED ELECTROLYSIS TEST LEADS ARE SPECIFIED FOR WATP CABLE. ANODES MAY BE CONNECTED TO ONE WIRE OF THE PAIRED ELECTROLYSIS TEST LEADS, HOWEVER, AT THE POINT OF ATTACHMENT OF THIS PAIRED TEST LEAD TO THE WIRE ARMOR IT IS NECESSARY THAT CONNECTION BE MADE TO ALL ARMOR WIRES AS OUTLINED IN NOTE 4.	1 &-2. OR 3
	PAIRED ELECTROLYSIS CURRENT FLOW LEADS SHOULD BE PROVIDED ON TPC (NB) CABLE IN THE FUTURE.	

NOTE 1

ON CABLES MARKED WITH ASTERISKS (*) OR (**), THE OUTER METALLIC PROTECTION (GOPHER TAPE, STEEL TAPES, COPPER JACKET OR WIRE ARMOR) IS SEPARATED FROM THE LEAD SHEATH BY A TYPE OF MATERIAL NOT INTENDED TO BE A GOOD CONDUCTOR OF ELECTRICITY. HENCE THE TOTAL CURRENT ON THE CABLE WILL DIVIDE BETWEEN THE SHEATH AND THE OUTER METALLIC PROTECTION IN A COMPLEX MANNER.

NOTE 2

ON CABLES MARKED WITH A SINGLE ASTERISK (*) THE OUTER METALLIC PROTECTION IS NORMALLY ELECTRICALLY CONNECTED TO THE SHEATH AT ADJACENT SPLICE POINTS. ON TAPE ARMORED AND WIRE ARMORED CABLES, THE ELECTROLYSIS CURRENT FLOW TEST LEADS ARE NORMALLY BRIDGED OVER A SECTION OF THE OUTER STEEL PROTECTION ONLY. THUS WITH LARGE DISTANCES BETWEEN SPLICE POINTS THERE MAY BE A CURRENT PICKUP AND CURRENT LOSS BETWEEN THE OUTER STEEL PROTECTION AND EARTH AND CURRENT FLOW MEASUREMENTS ON THE OUTER STEEL PROTECTION ONLY MAY BE INDICATIVE OF CONDI-

NOTE 2 (CONT'D)

TIONS ON THE OUTER PROTECTION ONLY. ON GP CABLES THE STEEL TAPE IS LASHED TO THE LEAD SHEATH AT SPLICES AND POINTS OF ATTACHMENT OF ELECTROLYSIS CURRENT FLOW TEST LEADS. THE CURRENT MEASURED WILL BE THE COMBINED CURRENT ON LEAD SHEATH AND STEEL TAPE.

NOTE 3

ON CABLES MARKED WITH A DOUBLE ASTERISK (**), THE OUTER METALLIC PROTECTION, (COPPER JACKET OR WIRE ARMOR), IS PURPOSELY KEPT ISOLATED FROM THE LEAD SHEATH BY THE THERMOPLASTIC INSULATION. BARRING FAULTS IN THE THERMOPLASTIC INSULATION, THE MEASUREMENT OF CURRENT FLOW ON THE OUTER PROTECTION WILL BE INDICATIVE OF THE CURRENT FLOWING ON THE OUTER PROTECTION FROM A CORROSION STANDPOINT.

NOTE 4

ALL ARMOR WIRES MAY BE BONDED TOGETHER BY PLACING COAXIALLY ALONG THE TOP SIDE OF THE WIRE ARMOR A PIECE OF BONDING RIBBON OF SUFFICIENT LENGTH TO COVER ONE COMPLETE SPIRAL OF ONE ARMOR WIRE. THE BONDING RIBBON SHOULD THEN BE SOLDERED TO EACH ARMOR WIRE UNDER THE BONDING RIBBON. ABOUT

NOTE 4 (CONT'D)

THREE FEET OR SO OF BONDING RIBBON WILL BE REQUIRED. COVER OVERALL WITH TWO LAYERS OF TAPE COAT.

ON SWA, DWA AND SUBMARINE CABLES THE ARMOR WIRES ARE TERMINATED BY MEANS OF A CLAMPING RING WHICH MAKES CONTACT WITH ALL ARMOR WIRES AND ANODES MAY BE CONNECTED TO ONE OF THE PAIRED ELECTROLYSIS LEADS IF TERMINATED AT THIS POINT WITHOUT SOLDERING THE ARMOR WIRES TOGETHER AS OUTLINED ABOVE. ON LWA CABLES THE CLAMPING RING IS NOT SPECIFIED WHERE ARMOR WIRES ARE TERMINATED AND IT WILL BE NECESSARY TO SOLDER THE ARMOR WIRES TOGETHER AS OUTLINED ABOVE. UNLESS CONTACT IS MADE TO ALL ARMOR WIRES AT EACH END OF THE 30 FOOT SECTION SPANNED BY THE ELECTROLYSIS CURRENT FLOW TEST LEADS, THE ZERO RESISTANCE AMMETER METHOD (NULL METHOD) WILL NOT INDICATE THE TOTAL CURRENT FLOWING ON THE WIRE ARMOR.

CAUTION:

THERE MAY BE ONE OR MORE WIRES ON A MARKER NOT CONNECTED TO THE CABLE. TESTS SHOULD BE MADE TO SEE THAT THE WIRE TO WHICH THE ANODE IS TO BE CONNECTED IS ALSO CONNECTED TO THE CABLE.

FIG. 1

FIG. 2

FIG. 3

FIG. 4

MTA CABLE ONLY NO GAS VALVE PIPE

FIG. 5

MTA CABLE ONLY NO GAS VALVE PIPE

FIG. 6

FIG. 7

FIG. 8

FIG. 9

ELECTROLYSIS TEST LEADS (PAIRED)
GAS VALVE PIPE (MAY BE AT EITHER END OF SPLICE)
SPLICE OR SHEATH OPENING
DIRECTION OF INCREASING MARKER NUMBERS
GAS VALVE PIPE (MAY BE AT EITHER END OF SPLICE)
ELECTROLYSIS TEST LEADS (PAIRED)
SPLICE OR SHEATH OPENING
DIRECTION OF INCREASING MARKER NUMBERS
ELECTROLYSIS TEST LEADS (PAIRED)
ELECTROLYSIS TEST LEADS (PAIRED)
ANODE LEAD
S OR W
10'
DIRECTION OF CURRENT FLOW
ANODE LEAD
ELECTROLYSIS TEST LEADS (PAIRED)
10'
N OR E
DIRECTION OF CURRENT FLOW
ELECTROLYSIS TEST LEADS (SINGLE)
GAS VALVE PIPE (MAY BE AT EITHER END OF SPLICE
SPLICE OR SHEATH OPENING
DIRECTION OF INCREASING MARKER NUMBERS
GAS VALVE PIPE (MAY BE AT EITHER END OF SPLICE)
ELECTROLYSIS TEST LEADS (PAIRED)
SPLICE OR SHEATH OPENING
DIRECTION OF INCREASING MARKER NUMBERS
POSSIBLE GAS VALVE PIPE
ELECTROLYSIS TEST LEADS (SINGLE)
ANODE LEAD
POSSIBLE SPLICE OR SHEATH OPENING (MAY BE ON EITHER SIDE OF TEST LEADS)
S OR W
DIRECTION OF CURRENT FLOW
ANODE LEAD
ELECTROLYSIS TEST LEADS (SINGLE)
POSSIBLE GAS VALVE PIPE
POSSIBLE SPLICE OR SHEATH OPENING (MAY BE ON EITHER SIDE OF TEST LEADS)
N OR E
DIRECTION OF CURRENT FLOW

Figure 4—Form MAW-214 (notes in connection with the application of anodes to buried cable and figure numbers for use with Figure 3.)

applied drainage currents, the current loss area can be mitigated by installing magnesium anodes on each side of the current loss area to reduce to zero the natural galvanic currents entering the loss area. The anode currents at each end should be adjusted with the anodes at the opposite end disconnected. This is the simplest solution.

2. In those cases where the anode drainage current attenuates at a faster rate than the natural galvanic current existing, a distributed system of anodes will be required throughout the loss area.

Figure 3 shows a form prepared to assist in the adjustment of anode currents and to provide a record of "before" and "after" conditions. A companion to this form is shown in Figure 4. This latter form indicates the preferred method of connecting anodes to the various types of cables for various directions of current flow and various test lead arrangements which have been used in the past.

Economic Aspects of Mitigative Measures

The amount of current flowing on a cable, the length of cable over which current discharge is taking place and the corrosion rate of the metal are the major factors affecting the life of a buried cable from a corrosion standpoint. By applying the following assumptions to these factors it is the author's opinion that the life of a buried cable may be predicted.

1. The rate of discharge of the current to earth follows a logarithmic curve.
2. The insulation resistance of the impregnated jute covering, flooded with hot asphalt, is uniform along the cable resulting in a uniform current discharge to earth over any one foot of cable being considered.

Although the validity of these assumptions may be questionable, they provide the basis for the preparation of a nomograph which the author believes may be used as a guide to determine whether remedial measures may be economically applied to specific lengths of buried cable.

Figure 5 shows a nomograph which has been prepared for certain types of lead sheath cables. The probable life of the lead sheath in years is estimated by drawing two straight lines as indicated in the key on the nomograph.

Even if the assumptions mentioned above do not hold and the life in years of the cable is actually much shorter, it is believed a factor may be applied based on local conditions and experience which will

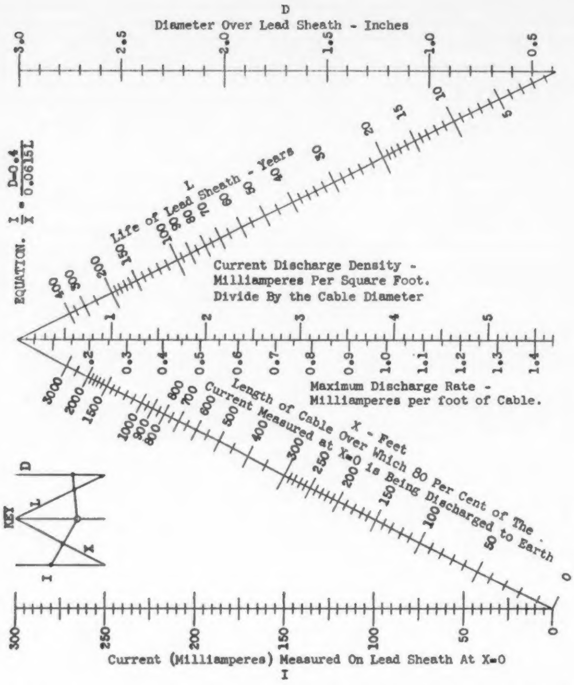


Figure 5—Nomograph used in determining the life of the lead sheath of gopher protected, jute protected, and buried tape armored toll cables. This device can be used when the current on the lead sheath is known and the length of cable is known over which 80 percent of the current is being discharged to earth or to the tape armor through the moist jute. Uniform leakage resistance to earth per foot of cable is assumed. Note regarding use of nomograph: Scales I and X may be multiplied or divided by the same number without changing the value of the equation.

permit use of the nomograph for estimating purposes. The corrosion rate used in the nomograph is based on the maximum rate of discharge of the measured current per unit of length within the length of cable over which tests indicate the discharge is taking place.

The length of cable over which the discharge is taking place should first be determined by Surface Potential Gradient Tests. The maximum rate of current discharge should also be determined from measurements of the current on the cable at each end of the discharge area by the null or zero resistance ammeter method mentioned previously.

From the measurements of current and the length of structure over which the discharge is occurring, reference to the nomograph will give the maximum current discharge over a one foot length of the structure and the life expectancy of the structure with this current density. It may then be determined on a cost basis whether the installation of cathodic protection measures immediately, or replacing the structure when it fails, will provide the most economical result.

A general rule might be to apply remedial measures if the estimated life of the structure as determined from the application of the test results to the nomograph is less than the assumed life of the structure used in calculating its depreciation rate. It should also be noted that although the remedial measures applied are designed to prevent possible corrosion trouble in the area where the current loss is greatest, the structure adjacent to the area of greatest current loss would also receive a certain amount of cathodic protection.

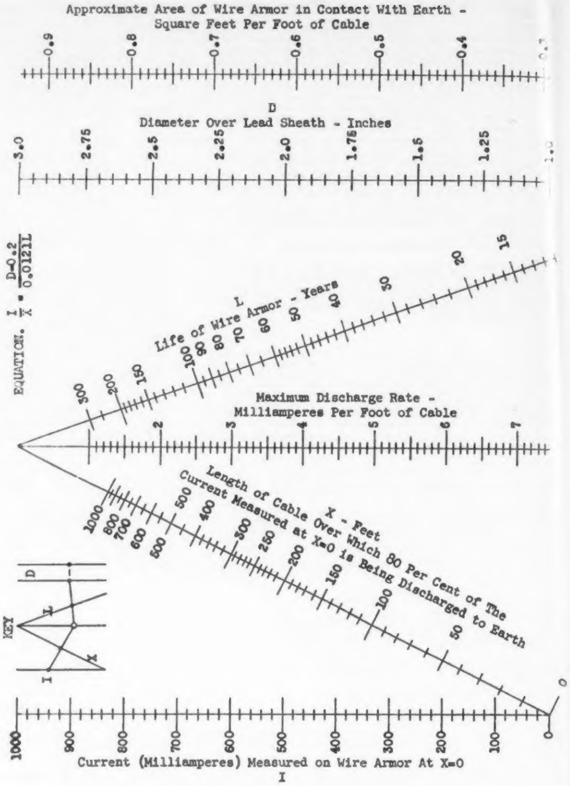


Figure 6—Nomograph for determining the life of the wire armor of single wire armored cables when the current on the wire armor is known and the length of the cable is known over which 80 percent of this current is being discharged to earth. Uniform leakage resistance to earth per foot of cable is assumed. Note: The I and X scales may be multiplied or divided by the same number without changing the value of the equation. To find maximum discharge density in milliamperes per square foot of wire armor divide maximum discharge rate by square feet of wire armor area per foot of cable.

Exceptions to the above general rule would be where the structure passes under a body of water, such as a flooded rice field, lake, creek or low area, which might be difficult to handle in case of an emergency. Intercity telephone cables which frequently cross lakes, creeks, rivers, drainage ditches and the like are often of the buried wire armored type in such sections. The current loss on such cables in some cases might conceivably be confined to the galvanized armor wires. By determination of the current loss area using the Surface Potential Gradient method of testing as discussed previously and from a knowledge of the magnitude of the current flow, a nomograph such as shown in Figure 6 for the steel wire armor might indicate the probable life to be expected.

The armor wires may however corrode even though there is no apparent current flowing on them and an extremely long life such as the nomograph might indicate cannot be accurately predicted.

Where sections of wire armored cables have been installed for mechanical protection against dredging

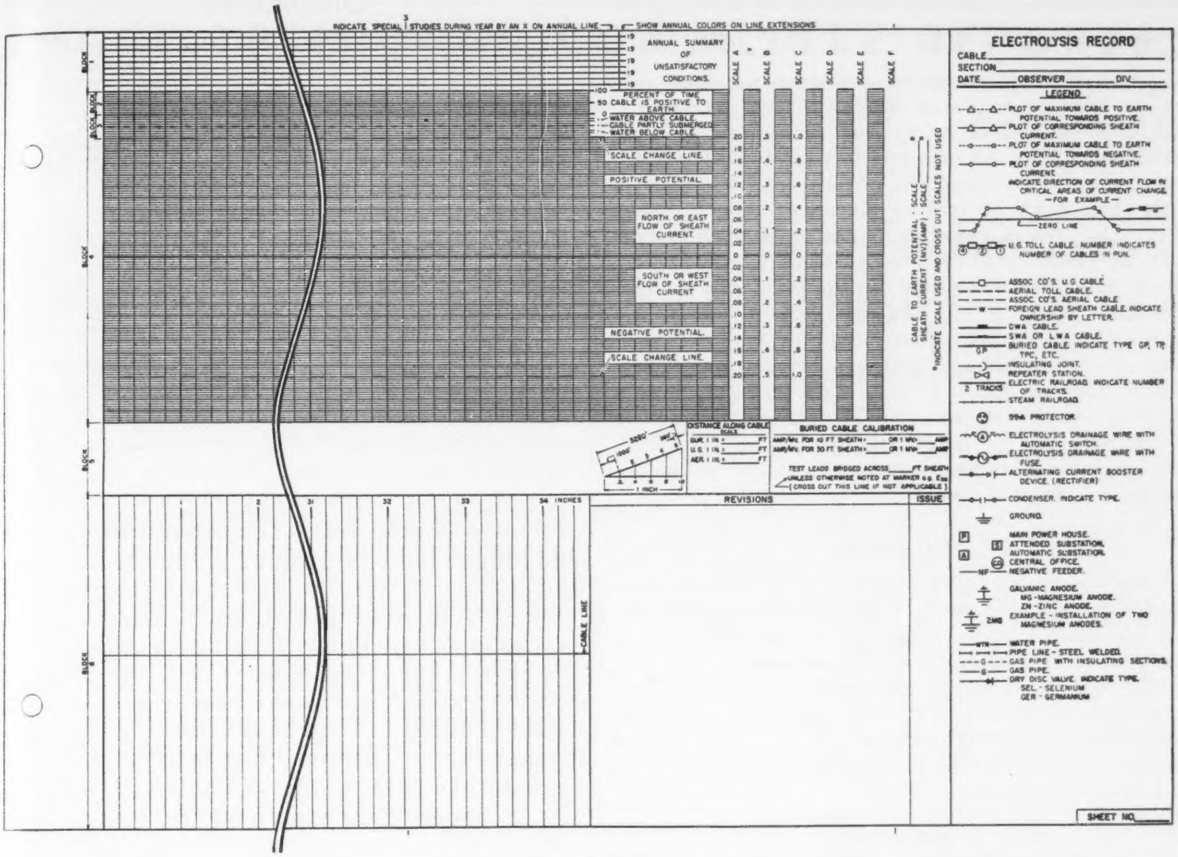

INDICATE SPECIAL STUDIES DURING YEAR BY AN X ON ANNUAL LINE
SHOW ANNUAL COLORS ON LINE EXTENSIONS
BLOCK
ANNUAL SUMMARY OF UNSATISFACTORY CONDITIONS.
PERCENT OF TIME CABLE IS POSITIVE TO EARTH.
WATER ABOVE CABLE.
CABLE PARTLY SUBMERGED
WATER BELOW CABLE.
SCALE CHANGE LINE.
POSITIVE POTENTIAL.
NORTH OR EAST FLOW OF SHEATH CURRENT
SOUTH OR WEST FLOW OF SHEATH CURRENT
NEGATIVE POTENTIAL.
SCALE CHANGE LINE.
SCALE A
SCALE B
SCALE C
SCALE D
SCALE E
SCALE F
CABLE TO EARTH POTENTIAL - SCALE
SHEATH CURRENT (MV)(AMP) - SCALE
*INDICATE SCALE USED AND CROSS OUT SCALES NOT USED
DISTANCE ALONG CABLE
BUR. 1 IN = FT
U.G. 1 IN = FT
AER. 1 IN = FT
1 INCH
BURIED CABLE CALIBRATION
AMP/MV. FOR 10 FT SHEATH = OR 1 MV = AMP
AMP/MV. FOR 30 FT SHEATH = OR 1 MV = AMP
TEST LEADS BRIDGED ACROSS FT SHEATH UNLESS OTHERWISE NOTED AT MARKER e.g. E30 (CROSS OUT THIS LINE IF NOT APPLICABLE)
31
32
33
34 INCHES
REVISIONS
ISSUE
CABLE LINE
ELECTROLYSIS RECORD
CABLE
SECTION
DATE OBSERVER DIV.
LEGEND
PLOT OF MAXIMUM CABLE TO EARTH POTENTIAL TOWARDS POSITIVE.
PLOT OF CORRESPONDING SHEATH CURRENT.
PLOT OF MAXIMUM CABLE TO EARTH POTENTIAL TOWARDS NEGATIVE.
PLOT OF CORRESPONDING SHEATH CURRENT.
INDICATE DIRECTION OF CURRENT FLOW IN CRITICAL AREAS OF CURRENT CHANGE. —FOR EXAMPLE—
ZERO LINE
U.G. TOLL CABLE. NUMBER INDICATES NUMBER OF CABLES IN RUN.
ASSOC CO'S. U.G CABLE.
AERIAL TOLL CABLE.
ASSOC. CO'S. AERIAL CABLE.
FOREIGN LEAD SHEATH CABLE. INDICATE OWNERSHIP BY LETTER.
DWA CABLE.
SWA OR LWA CABLE.
BURIED CABLE. INDICATE TYPE GP, TP, TPC, ETC.
INSULATING JOINT.
REPEATER STATION.
2 TRACKS
ELECTRIC RAILROAD. INDICATE NUMBER OF TRACKS.
STEAM RAILROAD.
99A PROTECTOR.
ELECTROLYSIS DRAINAGE WIRE WITH AUTOMATIC SWITCH.
ELECTROLYSIS DRAINAGE WIRE WITH FUSE.
ALTERNATING CURRENT BOOSTER DEVICE. (RECTIFIER)
CONDENSER. INDICATE TYPE.
GROUND.
MAIN POWER HOUSE.
ATTENDED SUBSTATION.
AUTOMATIC SUBSTATION.
CENTRAL OFFICE.
NF
NEGATIVE FEEDER.
GALVANIC ANODE. MG - MAGNESIUM ANODE. ZN - ZINC ANODE.
2MG
EXAMPLE - INSTALLATION OF TWO MAGNESIUM ANODES.
WATER PIPE.
PIPE LINE - STEEL WELDED.
GAS PIPE WITH INSULATING SECTIONS.
GAS PIPE.
DRY DISC VALVE. INDICATE TYPE. SEL. - SELENIUM GER - GERMANIUM
SHEET NO.

Figure 7—Electrolysis record.

operations, boat anchors, creek banks washing out, etc., cathodic protection for the armor wires is essential. Where sections of wire armored cables have been used only as a means of mechanical protection during construction, cathodic protection for the armor wires frequently may be considered as not necessary.

Corrosion Protection Record

The number of miles of cable installed, the variety of types of cable, together with such various items as (1) the location of current flow test points, (2) pressure testing valves, (3) insulating joints, (4) pipe lines and railway crossings, (5) cathodic protection systems on other structures, (6) magnesium anode or rectifier installations, and (7) paralleling pipe lines and railway systems, has made it desirable to provide some kind of suitable record for the use of electrolysis testers and for reference purposes. Since these items have such an important bearing upon the electrolysis test results, the form herein described was devised so that a plot of the electrolysis test results and the plant layout would be coordinated on the same record.

Figure 7 shows the two ends of this form. The form is approximately 11 inches high and 44 inches long overall and is divided into blocks of several sizes. Block numbers are shown on the left hand side of the form. Block 5 for example, is used to indicate marker, station or manhole numbers. On the right hand side of the form is shown the essential information for its use.

The most commonly used scales for current and potential measurements are indicated at the right hand end of the form. Blank optional scales are also provided for the insertion of other scale values if desired. There are 14 major scale divisions each side of the zero line. The scale may be made uniform over the entire 14 divisions or uniform over 10 divisions, then changed to a larger scale for the remaining 4 divisions. The 10th line is shown dashed and indicated as a scale change line. This scale changing feature permits occasional high values of current or voltage to be recorded without congesting a large number of small values of current or voltage readings.

In using the form, the plant layout is placed in Block 6 and the marker or manhole numbers in Block 5 of the form. A film or Van Dyke negative is then made. The film negative will produce the best subsequent prints and it can be used repeatedly. The film negative is used for plotting of annual routine measurements or special voltage and current readings. The form will appear in proper order when viewed from the back side of the film negative and the plots of voltage and current can be made on the back side of the film in pencil. Repeated erasures can be made of the pencil lines. Minor changes in the layout can also be made on the film if desired, by scraping off any existing information and adding the new information.

Unsatisfactory corrosion conditions needing corrction may be indicated in Block 1 by making the annual line a solid heavy line throughout the unsatisfactory area. An unsatisfactory condition for which correction is not considered justified may be shown in this same block by making the annual line a dashed heavy line throughout the area in question. By transferring this information to the original copy of the form annually as required, one original can be used for nine years.

The type of chart illustrated, for maintaining a record of conditions along the route of a long buried cable, has been found to be of value not only from a testing standpoint but also in relating changes in conditions due to the proximity of other structures or cathodic protection systems installed in the vicinity of the cable route.

Conclusions

The above discussion is intended to present some of the factors involved in considering the application of corrosion control measures to buried intercity communication cables. It will be noted from the foregoing that many factors are involved and that measurements of "structure to earth potential" and "current on structure" are only two of the criteria which must be considered in the application of protection to buried cables.

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5. Daniel R. Werner. Earth Potential or Surface Potential Gradient Tests on Buried Cables. *Corrosion*, **12,** 376t (1956) Aug.
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DISCUSSION

Question by Frank E. Kulman, Consolidated Edison Company of New York, New York, N. Y.

The nomographs enable the prediction of cable life. Is this the probable life of the galvanizing, the life of the steel armor protection, or the time for penetration of the lead sheath?

Reply by Daniel R. Werner:

Figure 5 covers the determination of the life of the lead sheath of certain types of buried lead sheath telephone cable. It is based on 100 percent of the metal being consumed. The corrosion rate is not expected to be uniform and a gas leak in the lead sheath may develop in much less time than the nomograph indicates. Thus a correction factor would have to be applied to the indicated life. It would be nice to be able to predict the lead cable sheath life but the thought behind the preparation of the nomograph was to provide some guide to assist the maintenance people in deciding whether remedial measures should be applied now or later.

Figure 6 covers the determination of the life of the armor wires only of single wire armored lead sheathed cable based on the amount of steel in the armor wires. It is based on 100 percent of the wires being consumed. Although the armor wires are galvanized, the effect of this galvanizing is neglected in the nomograph. The galvanizing, until it is consumed, might increase the expected life of the armor wires about ten years over what the nomograph shows. The nomograph indicates that the life of the armor wires alone could be several times ten years with the smaller amounts of current. The steel armor wires, being bonded to the lead sheath at the splices, act as a sacrificial anode to the lead sheath in acid or neutral soil conditions. Where wire armored cables are concerned, it appears that the steel of the armor wires is most influential in extending the life of the lead sheath.

NACE TECHNICAL COMMITTEE REPORTS

Publication 57-12

*A Report of the Test and Inspection Work Group**

Evaluation of Laboratory Testing Techniques For Cooling Water Corrosion Inhibitors

Task Group T-5C-1 on Corrosion by Cooling Waters (South Central Region)**

Abstract

Four laboratory corrosion inhibitor testing techniques were employed to determine the best method of testing and to set up specifications for carrying out these tests. The conclusions were that the dynamic flow test is the only one which gives accurate screening of inhibitors for use in recirculated systems. The static test can be applied to storage of water. It was also concluded that an inhibitor must be run in a pilot plant for quantitative data on inhibition of corrosion, scaling, pitting, tuberculation, and effect on heat transfer. Specifications for carrying out laboratory and pilot plant tests have been set up and some recommendations for plant procedure are made. **2.3.4.**

Introduction

THE TEST and inspection subcommittee of T-5C-1 on Corrosion in Gulf Coast Cooling Waters has completed the project of evaluation of four laboratory testing techniques for cooling water corrosion inhibitors. This project was initiated in December, 1953 to determine differences in the order of merit of inhibitors when tested by different laboratory techniques. A survey of member companies of T-5C-1 revealed that each company had its own preferred method of screening inhibitors in the laboratory with no knowledge of how the different methods correlated with each other and with plant conditions. The subcommittee set up two sets of tests. The first was conducted in make-up Brazos river water, using 100 ppm of all inhibitors and a pH of 6.5. The second set was in Brazos river water, which had been concentrated 2.5 times in the Carbide and Carbon Chemicals Company's cycle water pilot plant, using the vendors' recommendations with respect to inhibitor concentration and pH control.

Test Results

All tests were run in strict compliance with appended specifications. Table 1 gives analyses of water used in both tests and Table 3 shows inhibitor concentrations and pH values for the concentrated water tests. Inhibitor "B" in the unconcentrated water tests was orthophosphoric acid. The inhibitors were of different generic types and code letters were used for identification. The trade names are not mentioned in this report for obvious reasons. Tables 2 and 4 list the order of merit of the inhibitors as determined by the several test methods in make-up and concentrated Brazos river water respectively. Data are also included from the cycle water pilot plant for comparison. The pilot plant is constructed to simulate field conditions with the exclusion of process contaminants.

The merit ratings of the several methods of testing show that the dynamic flow test correlates best with the pilot plant test data. The spinning rod and spinning disc tests rated the inhibitors, in a random manner, differently from each other and from the dynamic flow test. The static test showed very little difference among inhibitors and the ratings differ considerably from those in other tests. Both pilot plant and dynamic flow tests rejected two inhibitors due to very poor protection, while none of the other methods rejected any inhibitors.

The conclusions drawn from the data in Tables 2 and 4 are that the dynamic flow test is preferable to the other laboratory tests for screening inhibitors for cooling water corrosion in recirculating systems. The static test is of value only when quiescent conditions are encountered, as in water storage.

Specifications for Testing Cooling Water Corrosion Inhibitors

Part 1—Reporting Data

It is recommended that the following standard procedures be followed so data from various sources may be compared and evaluated.

1. Report all corrosion data in inches penetration per year. In cases where specimens are exposed in duplicate or triplicate, report data on individual specimens so that the normal variations among specimens may be established. Describe the conditions of exposure of the coupons if they are not the same in each case.

2. Report the frequency and severity of pitting. Frequency is defined as the percentage of the total area which is pitted. Actual pit counts are desirable, but in most cases limited facilities and

TABLE 1—Analysis of Brazos River Water

	Make-Up (Nov., 1954)	Concentrated 2.5 Times (Sept., 1956)
Chlorides	60 ppm	958
M alk.	105	159
P alk.	0	10
T hardness	152	700
Ca as $CaCO_3$	117	530
Mg as $CaCO_3$	36	167
Silica	10.4	20
Sulfates	30	594
Turbidity	85	....
pH	7.5	8.5
T solids	260	2251

TABLE 2—Tests in Make-Up Brazos River Water
100 ppm Inhibitor at pH 6.5

Inhibitor Rating	Dynamic Flow	Spinning Rod	Spinning Disc	Static	Pilot Plant
1 (best)	C	A	D	B	C
2	D	E	C	D	D
3	E	D	A	A	E
4	A*	B	B	C	A*
5 (worst)	B*	C	E	E	B*

* Rejected.

TABLE 3—Inhibitors, Concentrations and Controls

Inhibitor	General Type	PPM	Control	pH
A	Ferricyanide-polyphosphate	50	30 ppm total phosphate	5.8—6.3
C	Chromate-polyphosphate	50	17-20 ppm total phosphate	5.8—6.3
D	Organic chromate	50	25-30 ppm chromate	M. Alk. 50-75 ppm
E	Zinc-polyphosphate	40	12-15 ppm meta phosphate	6.6—7.3
F	Phosphate-amine ester	75	25-30 ppm total phosphate	5.8—6.3

TABLE 4—Tests in Brazos River Water Concentrated 2.5 Times

Inhibitor Rating	Dynamic Flow	Spinning Rod	Spinning Disc	Static	Pilot Plant
1 (best)	C	F	F	A	C
2	F	C	A	E	D
3	D	E	C	C	E
4	E	D	D	D	A*
5 (worst)	A*	A	E	F	..

* Rejected.

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* L. M. Roger, Carbide and Carbon Chemicals Co., Texas City, Texas.

** C. P. Dillon, Carbide and Carbon Chemicals Co., Texas City, Texas.

the time involved are prohibitive. Severity of pitting should be reported as maximum pit depth in inches per year if facilities for measuring this are available (microscope or micrometer).

3. Give a general description of the type of pitting and of the coupons before cleaning, outlining the amount and type of corrosion products present.

4. Describe scale on heat exchange surfaces if any is present.

5. Give the generic type of inhibitor, its concentration, pH and velocity of the test solution.

Part 2—Specimen Preparation and Cleaning

1. Specimens are to be cut from cold rolled SAE 1020 steel and be finished to a 120-grit surface. Weigh the specimen to the nearest .0001 gram on an analytical balance.

2. To clean the specimens after exposure wash with soap or mild abrasive using a rubber stopper or tooth brush to remove the corrosion products.

3. Clean to bare metal using reagent grade concentrated hydrochloric acid inhibited with 5 percent stannous chloride and 2 percent of antimonious oxide by weight.

4. Wash the acid-cleaned specimens with water, dry them and place in a desiccator until weighed.

Part 3—Laboratory Testing

A. Static Test

1. Prepare coupons according to procedure outlined above.
2. Use 200 cc of water per sq. in. of exposed coupon.
3. The water should be air saturated and changed each 24 hours.
4. Test duration is 14 days under quiescent conditions.
5. Temperature is to be room temperature unless other data is especially desired. Report the temperature.

B. Spinning Disc

1. Use 2-inch diameter discs with 200 cc of water per sq. in. of exposed coupon.
2. Test duration is 24 hours in the absence of aeration.
3. Prevent any vortex from touching the specimens.
4. Run tests at room temperature.
5. Insulate test specimens and report the rpm of the disc.

C. Spinning Rod

1. The procedure for the spinning rod test is the same as for the spinning disc except for the coupon. The rpm and diameter of the rod should be reported.

D. Dynamic Flow

1. Place two test coupons in the reservoir, which must have a minimum capacity of 5 gallons.
2. Place two or more test nipples in the discharge of the centrifugal pump connected in series with rubber tubing. The test nipples may be 3 inches long by ⅝ inches in diameter by 14-inch gauge. These nipples must be protected externally from atmospheric corrosion by either grease or clear (removable) plastic.
3. Use at least 200 cc of water per sq. in. of exposed coupon per day of exposure.
4. Test duration is 100 hours with daily determinations of inhibitor concentration and pH of the system.
5. Maintain the level of the system constant using distilled make-up water.
6. Using immersion heater and thermostatic controls, maintain the temperature which corresponds most closely with the main cycle towers.
7. Report the linear velocity of the water through the test nipples.

Do not pretreat specimens in higher inhibitor concentrations before exposure.

Laboratory tests are to be used as screening tests only to eliminate materials which obviously are not suited to the cooling system in question. The dynamic flow test is preferred for most tests except where specific problems are encountered which conform to one of the other procedures.

Part 4—Pilot Plant Tests

1. The system should have a minimum capacity of 5000 gallons.

2. A test heat exchanger with removable tube bundle should be used and the old tubes replaced with new tubes after each run.

3. The choice of coupons or test nipples is optional.

4. A minimum test duration of four weeks is to be used with one test coupon evaluated after each week's exposure.

5. The cycles of concentration of water in the pilot plant should correspond to the plant cooling cycle. A complete water analysis should be made daily and inhibitor concentration and pH measurements should be made hourly during the run.

6. The velocity of water and temperature of the heat exchanger should correspond to plant conditions as nearly as possible, with the water on the tube or shell side depending on plant conditions.

7. In addition to the standard reporting of data, as outlined above, the heat exchanger should be photographed before and after cleaning for a permanent record. Test nipples should be split open after exposure for examination after the weight loss has been determined.

8. The heat exchanger should have temperature measuring devices on the steam and water inlets and outlets and the water flow rates controlled so that heat transfer data may be calculated.

The pilot plant will give very reproducible quantitative data if it is designed so that conditions are constant between runs of different inhibitors. The design must correspond as nearly as possible to plant conditions with respect to velocities, temperatures, pH, etc., for the most useful results.

Tests in the plant cooling cycle are not standardized here because the various systems differ considerably with respect to process contamination and other variables such as those mentioned in the previous paragraph. The following suggestions are offered concerning the plant tests:

1. In reporting plant test data, a complete water analysis should be made once during the test and reported along with the control analyses made during the period. Any unusual occurrence, such as extremely high or low pH values, should be reported even though it is of short duration.
2. A time-corrosion rate curve should be plotted.
3. The test duration should be a minimum of four weeks.
4. A test heat exchanger with a removable tube bundle may be installed to evaluate scaling and pitting. In addition to visual examination, scale can be evaluated by heat transfer data if the proper temperature measuring devices are employed.
5. The velocities through the heat exchanger and test nipples should be reported.

NACE TECHNICAL COMMITTEE REPORTS

Publication 57-14

Second Interim Report

Tentative Recommended Specifications for

Asphalt Type Protective Coatings For Underground Pipe Lines—Mastic Systems

By NACE Technical Unit Committee T-2H
On Asphalt Type Pipe Coatings*

Section 1—Description

1.1 Mastic systems for pipe lines shall consist of a prime coat followed by a coating of a dense, impervious, essentially voidless mixture of asphalt, mineral aggregate and mineral filler which may include asbestos fibre. The minimum permissible thickness shall be ¼ inch. The finished mastic coating shall be painted with a whitewash.

1.2 The coating system shall be selected by the engineer and shall conform to one of the types specified in paragraph 2.7.

Section 2—Materials

2.1 Asphalt Primer—The asphalt primer shall be homogeneous, free from water and shall meet the following requirements:

Bond strength, 32 F, psi (mastic to primer)	150+
Bond strength, 77 F, psi (mastic to primer)	75+
Flash point (open tag), ° F	100+
Furol viscosity at 77 F, sec.	50-150
Distillation:	
Distillate (percent of total distillate to 680° F)	
To 437 F	75+
To 500 F	87+
To 600 F	97+
Residue from distillation to 680 F, volume percent by difference	30-45
Tests on residue from distillation:	
Penetration at 77 F, 100 g, 5 sec.	2-12
Softening point (ring and ball), ° F	190-220
Percent soluble in CCl_4	99+

2.2 Asphalt Binder—The asphalt binder shall be petroleum asphalt containing no mineral matter other than that naturally present in the asphalt. It shall be uniform in character, free from water and shall not foam when heated to 400 F. The engineer shall select the grade to be used as determined by the intended pipe line operating temperature. The grade selected shall meet the following requirements when tested in accordance with the methods enumerated in Table 1.

2.3 Mineral Aggregate—The mineral aggregate shall consist of properly graded, clean, nonmicaceous, dust-free sand and mineral filler such that, when blended, the mixture shall be within the limits specified in Table 2. The material shall be sound and may be either the loose, granular product resulting from the natural disintegration of rock, or the product of crushing larger material. Mineral filler shall be added to the sand only in sufficient amount to obtain the specified tolerances on the fine aggregate.

TABLE 1—Asphalt Binder Characteristics

	GRADE			
	I	II	III	IV
Operating temperature, °F	80—	125—	160—	210—
Softening point (Ring and Ball), °F	150-175	175-200	200-220	250-265
Penetration at 77 F, 100 g, 5 sec	21-25	15-17	7-11	5-8
Flash point (Cleveland Open Cup), °F	450+	450+	450+	450+
Loss on Heating at 325 F, 5 hour, percent	0.5—	0.5—	0.5—	0.5—
Ductility at 77° F, cm	3.5+	2.5+	1.0+	0+
Percent soluble in CCl_4	99.0+	99.0+	99.0+	99.0+

2.4 Mineral Filler—The mineral filler shall consist of thoroughly dry limestone dust or other mineral dust approved by the engineer. It shall be free from lumps and loosely bonded aggregations. When tested by means of laboratory sieves, it shall meet the following requirements:

Sieve Size No.	Passing, Percent by Weight
30	100
100	85+
200	65+

Abstract

Asphalt-type mastic systems for application to underground pipe lines are described, materials characteristics specified and application methods and minimum satisfactory coatings indicated. Included among the recommendations are surface preparation criteria, priming methods, electrical inspection, pipe handling methods and maintenance. An appendix details methods for testing both bond strength for primers and pipe line coatings themselves. **5.4.5**

2.5 Asbestos Fiber—The asbestos fiber shall be willowed to give a loose density of not more than 10.5 lb. per cu. ft. It shall contain not more than 2 percent by weight of moisture.

TABLE 2—Mineral Aggregate Gradation

Sieve Size No.	Passing, Percentage by Weight for Coating Thickness	
	Coarse, Over $^{7}/_{16}$ Inch	Fine, Under $^{7}/_{16}$ Inch
4	100	......
10	67—90	100
40	33—39	36—43
100	26—32	28—33
200	19—23	23—26

TABLE 3—Mastic Mixture Characteristics

	GRADE			
	I	II	III	IV
Tensile strength at 32 F, lb./sq. in., min.	250	....	....	....
Tensile strength at 77 F, lb./sq. in., min.	125	150	160	165
Impact at 32 F, cm, min.	5	....	....	....
Impact at 77 F, cm, min.	7	7	5	5
Impact at 115 F, cm, min.	....	....	7	7
Bending at 32 F, sec., min.	25	....	....	....
Bending at 77 F, sec., min.	30	25	20	20
Bending at 115 F, sec., min.	....	....	25	25
Depression at maximum recommended operating temperature, percent of original thickness, max;				
5 Hours	30	30	30	30
10 Hours	50	50	50	50
50 Hours	75	75	75	75
Electrical resistance of depressed portion of coating after 50 hours in megohms/sq. ft.	100+	100+	100+	100+

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* Austin S. Joy, Brumley-Donaldson Co., Huntington Park, California, chairman.

2.6 Exterior White Coating—Whitewash for the painting of the exterior of mastic coated pipe line shall consist of quick lime mixed slowly with water in the proportion of two pounds of quick lime to one gallon of water.

2.7 Characteristics of Mastic Mixture—Mastic mixture shall meet requirements in Table 3 when tested in accordance with the methods hereinafter included.

2.8 Thickness of Mastic Coating—Minimum thickness of the mastic coating shall be ¼ inch. However, sufficient thickness shall be used to insure that the finished coating shall withstand a spark gap test of a potential that will jump between the electrodes spaced ¼ inch further apart than the maximum thickness of the applied coat.

2.9 Approval of Materials—Prior to use, a certified analysis of all materials proposed to be used under these specifications shall be submitted to the engineer. If requested, samples shall be submitted for test and analysis. No material shall be used until it has been approved by the engineer.

2.10 Methods of Testing—Except as otherwise noted, methods of testing shall be the latest revision of methods adopted by the American Society for Testing Materials.

a) Asphalt Primer

Bond Strength—See Appendix
Flash Point—Method of test approved by Bureau of Explosives, AASHO method of test T79
Viscosity—ASTM method of test D88
Distillation—ASTM method of test D402
Penetration—ASTM method of test D5
Softening Point—ASTM method of test D36
Solubility in Carbon Tetrachloride—ASTM method of test D4, except that CCl_4 is used instead of CS_2 as solvent, Method No. 1.

b) Asphalt Binder

Softening Point—ASTM method of test D36
Penetration—ASTM method of test D5
Flash Point—ASTM method of Test D92
Loss on Heating at 325 F—ASTM method of test D6
Ductility—ASTM method of test D113
Solubility in Carbon Tetrachloride—ASTM method of test D4, except that CCl_4 is used instead of CS_2 as solvent, Method No. 1
Sieve Analysis—ASTM method of test D546
Tensile Strength—See Appendix
Impact Test—See Appendix
Bending Test—See Appendix
Depression Test—See Appendix
Electrical Resistance—See Appendix

Section 3—Construction

3.1 Preparation of Surfaces—All oil and grease on the surfaces of the metal shall be removed thoroughly by flushing and wiping using a fresh petroleum solvent and clean rags. After cleaning, the pipe shall be protected from and maintained free of all oil, grease and dirt from whatever source until the pipe has received its final coating. All metal surfaces shall be thoroughly cleaned by blasting. Surfaces that rust before a priming coat has been applied shall be reprepared. Adequate air separators shall be used to remove effectively all oil and free moisture from the air supply to the blaster. Any pipe showing faults after preparation shall be set aside for reconditioning or rejection.

3.2 Asphalt Priming—The use of asphalt primer that becomes fouled with foreign substances or has thickened by evaporation of the solvent will not be permitted.

The primer shall be applied uniformly to the clean dry surface in a manner approved by the engineer. Bare spots or holidays shall be recoated with an additional application of the primer.

The engineer may require the pipe to be reprimed if undue delay or surface contamination occurs between the application of the prime coat and the coating application. When the primer has dried to an extent acceptable to the engineer, the mastic may be applied.

3.3 Asphalt Mastic Pipeline Coating Application—When it is necessary to blend two or more sands to produce the aggregate, each sand shall be weighed separately to insure accurate control of the final mixture. Each sand shall be thoroughly dried before weighing.

All sands shall be heated (not over 450 F) so that when run into the pug mill and mixed thoroughly with the proper amount of asphalt and limestone dust, the resulting temperature of the mastic mix shall be between 280-400 F.

The asbestos fiber shall be weighed out and willowed to give a density of not more than 10.5 lb. per cu. ft. just before adding to the hot aggregate and mineral filler in the pug mill.

The asphalt shall be heated to not over 425 F before it is weighed and run into the pug mill except Grade IV which may be heated to a maximum temperature of 460 F.

The hot mastic mixture shall be applied to the primed surface in a manner acceptable to the engineer.

3.4 Electrical Inspection—An electrical inspection of the completed coating shall be made by means of an approved electrical flaw detector and all defective areas shall be suitably patched.

3.5 Handling Coating Materials and Coated Pipe—All materials shall be transported and stored in such a manner as to prevent damage or contamination.

The coated pipe shall be handled in such a manner as to minimize damage. Wherever the coated pipe is supported, it shall be by means of slings or skids approved by the engineer. All bearings areas shall be inspected and damaged areas repaired.

Whenever the bottom of the ditch contains projecting rocks or hard objects which might puncture the protective coating, the bottom of the ditch shall be padded with a minimum of six inches of backfill material free of hard objects that might damage the coating.

The coated line shall be lowered in a manner satisfactory to the engineer.

The ditch shall be backfilled to a depth of at least one pipe diameter above the top of the pipe, unless directed otherwise by the engineer, with material free from hard or sharp objects which might damage the coating.

Backfilling shall be conducted at all times in a manner to prevent damage and abrasion to the exterior protection on the pipe.

3.6 Special Operations—Pipe sections, couplings, or fittings shall be joined together and protected in a manner acceptable to the engineer. However, extra thickness of mastic shall be required for all sections where the protection is manually applied.

3.7 Special Provisions for Shop-Protected Pipe—Shop-coated pipe shall at all times be stored and transported in such a manner as to prevent damage to the coating.

The length of pipe to be left bare at ends shall be in accordance with instructions supplied by the engineer.

3.8 Equipment—All equipment used in these operations shall be of a type satisfactory in all respects to the engineer. No equipment shall be used which may cause undue damage to the pipe or protective system.

3.9 Miscellaneous Provisions—Where river weights, supporting or anchoring devices, or special coating materials are used, they shall be attached or applied in such a manner as not to damage the protective coating. The river weights shall be given a protective coating.

Mill-coated pipe shall have a reflective surface adequate to minimize softening due to sunlight.

Section 4—Cathodic Protection

4.1 The engineer shall determine the extent of cathodic protection required.

4.2 When cathodic protection is installed, it shall be installed in accordance with procedures to be established by the T-2C Committee of NACE.

Section 5—Maintenance

5.1 Cathodic Protection—The degree of cathodic protection which may be established shall be maintained in accordance with the procedures established by the T-2C Committee of the NACE.

5.2—Coating Repairs—When excavations are made for leak repairs, tie-ins, lateral connections, or any other purpose, all damaged or deteriorated coatings shall be repaired.

Mastic Tensile Strength

3. Specimens of 1.0 square inch cross-sectional area, prepared in molds specified by ASTM C 190 and immersed in a water bath at 32 F ± 1 F for one hour, shall be removed from the water bath and immediately tested in a suitable tensile testing machine which is loaded at the rate of 50 ± 5 pounds per minute. After each test, the jaws which

hold the specimen shall be removed from the machine and immersed in the water bath until the next specimen is tested (usually about one minute). The load in pounds per square inch at which failure occurs shall be determined for three specimens and their average recorded as the mastic tensile strength at 32 F. Other specimens shall be tested in a similar manner for tensile strength at 77 F and the failure load recorded.

Mastic Bending Resistance

4. The resistance of the mastic to cracking during bending shall be measured at 32 F, 77 F and 115 F by the Purdue Test, in which a 1 x 4 x ¼ inch specimen is bent over a ¾ inch mandrel at the rate of 12 degrees per minute. The specimens shall be removed from the controlled-temperature water bath and tested immediately. The elapsed time in seconds from the start of the test until the first crack appears shall be determined, and the average for three test specimens at each specified temperature of 32 F, 77 F and 115 F shall be recorded as the mastic bending resistance at that temperature.

Mastic Impact Resistance

5. The impact resistance of the mastic shall be measured at 32 F, 77 F, and 115 F by a Page Impact Machine having a 2-kilogram hammer. The test specimens shall be cylindrical and shall be 2.5 centimeters in diameter and 2.5 centimeters high. The specimens shall be removed from the controlled-temperature water bath and tested immediately. Beginning at 1 centimeter height, the hammer of the impact machine shall be raised 1 centimeter before each succeeding blow is struck. The height to which the hammer must be raised in this manner to produce a crack in the specimen shall be obtained. The average value for three specimens at each of the three test temperatures (32 F, 77 F and 115 F) shall be determined and recorded as the impact resistance at that temperature.

Mastic Resistance to Deformation (Depression Test)

6. The specimen of mastic for this test shall be $\frac{7}{16}$ inch in thickness and at least 2 inches in diameter. A retaining ring shall encompass the specimen. The specimen shall be bonded by asphalt primer to a steel plate which has been sand blasted. The resistance of the mastic to deformation under pressure shall be determined by measuring the depression that occurs when a ¾ inch diameter flat-faced rod is pressed against the specimen with a pressure of 50 pounds per square inch after 5, 10 and 50 hours. The rod and sample shall be held at the specified maximum operating temperature (see Table 1) for the duration of the test. The mastic resistance to deformation shall be recorded as the depression expressed as a percentage of the original thickness. The depth of depression is measured by the drop in level of the penetrating rod and is determined by means of a depth micrometer.

Mastic Electrical Resistance

7. The crater in the specimen resulting from 50 hours of depression in the test for Mastic Resistance to Deformation shall be filled with $\frac{1}{10}$ normal sodium chloride solution and allowed to stand for 24 hours. The electrical resistance of the depressed portion of the coating shall be determined by attaching one lead of an ohmmeter to the steel backing plate and immersing the other lead in the salt solution. The resistance shall be recorded in megohms per square foot of the surface in the bottom of the depressed mastic, which shall be assumed to be ¾ inch in diameter.

Note: All test results that vary more than 10% from the averages shall be rerun.

APPENDIX

1. Test for Bond Strength of Asphalt Primer for Asphalt Mastic Coated Pipe Lines

Scope

1. This method is intended to measure the strength of the bond provided by asphalt primers between a mastic coating and a pipe line metal, when the test is conducted under standard conditions.

Apparatus

2. The apparatus shall consist of the following:

a. Mixing Equipment—The mixing equipment shall consist of a mixing bowl, a paddle and a suitable mixer.

b. Oven—The oven shall be of the convection ventilated type, capable of being maintained at a temperature of 375 ± 10 F.

c. Water Bath—The water bath shall be capable of maintaining specified temperatures of 32 F ± 1 F and 77 F ± 1 F.

d. Steel Plungers—Two cylindrical steel plungers, of 1.128 ± 0.001 inch diameter (1 square inch) and of sufficient length to be gripped firmly by the jaws of the testing machine. One end of each plunger shall be machined flat, and its plane shall be at right angles to the axis of the plunger. It shall then be sand blasted.

e. Mold—A hollow cylindrical steel mold shall have an inside diameter of 1.130 ± 0.001 inch.

f. Testing Machine—The testing machine shall be capable of maintaining a rate of loading of 50 ± 5 pounds per minute. It shall be provided with suitable jaws and universal joints so that the steel plungers bonded to the mastic by the asphalt primer can be gripped tightly and held in alignment as the load is applied.

Preparation of Test Specimens

3. a. Mixing of Mastic—The detachable mixing bowl and paddle and the aggregate mixture, shall be heated to 375 F ± 10 F in the oven. The bowl and paddle shall then be attached to the mixer and the required amount of asphalt binder added. Mixing shall continue for a period of 3 to 5 minutes. After mixing, the bowl containing the mastic shall be placed in the oven and allowed to stand at a temperature of 375 F ± 10 F for 10 minutes.

b. Priming of Pistons—The sandblasted end of each piston shall be covered with the asphalt primer to be tested, the primer being flowed onto the surfaces with a brush. The primed pistons shall be allowed to cure at room temperature for 24 hours and shall then, together with the mold, be placed in the oven and maintained at a temperature of 212 F ± for 30 minutes.

c. Bonding of Mastic to Pistons—A sufficient amount of the hot mastic to form a layer of approximately ¾ inch compacted thickness shall be placed between the primed surfaces of the plunger in the mold and compressed at 1500 pounds per square inch pressure for one minute by double plunger action. The plungers, with the mastic between them, shall then be carefully pushed from the mold, placed in a vertical position, and left to cool at room temperature for one hour. They shall then be immersed in the water bath, maintained at the specified testing temperature of either 32 F or 77 F for one hour.

Procedure

4. a. The specimen shall be tested immediately upon removal from the water bath.

b. The steel plungers shall be so placed in the testing machine that their long axes shall coincide with the direction of the applied pull through the center line of the grip assembly. The load shall be applied immediately at the rate of 50 ± 5 pounds per minute and shall be continued to failure. The load required to produce failure shall be reported as the mastic primer bond strength, expressed in pounds per square inch.

2. Methods of Testing Asphalt Mastic Pipeline Coatings

Scope

1. These methods cover the examination of asphalt mastics for use in the construction of asphalt protective coatings for pipelines.

Preparation of Test Specimens

2. A detachable mixing bowl and a paddle, and the aggregate mixture, shall be heated in an oven to a temperature of 375 F ± 10 F. The bowl and paddle shall then be attached to a suitable mixer and the required amount of asphalt added. Mixing shall be continued for a period of 3 to 5 minutes. After mixing, the bowl containing the mastic shall be placed in the oven maintained at 375 F ± 10 F and allowed to stand for 10 minutes. While still in the oven, portions of the mastic shall be removed as needed to prepare the test specimens. The total elapsed time that the mastic remains in the oven, however, shall not exceed 30 minutes. All test specimens shall be prepared in the following order:

a. Bending specimens
b. Impact specimens
c. Tensile strength specimens
d. Deformation specimens

Briquettes for testing shall be compressed at 1500 pounds per square inch in molds in which the necessary amount of the mastic has been placed. After cooling and curing at room temperature overnight, the briquettes shall be immersed in a water bath maintained at the specified temperature for at least one hour before testing. At least four specimens are required for each of the above tests.

NACE TECHNICAL COMMITTEE REPORTS

Publication 57-15

A Contribution to the Work of NACE Technical Unit Committee T-2C On Minimum Current Requirements

Some Observations on Cathodic Protection Criteria★

By L. P. Sudrabin* and F. W. Ringer**

Abstract

A comparison of cathodic protection criteria has been made on a 240-foot length of bare 6-inch pipe (steel) buried in 16,100—55,900 ohm. cm. soil. Anodic areas of representative size and position were established on the pipe by coupling high purity zinc plates through measuring circuits.

Some of the cathodic protection criteria observed simultaneously on the pipeline include: 1. Measurement of the closure circuit current flow between the zinc plates and the pipe. 2. The McCollum Earth Current Meter. 3. Pipe-to-reference electrode potential. (a. electrode remote. b. electrode on ground over pipe. c. electrode close to pipe.) 4. The "apparent" break in the pot.-log c.d. relation.

Further tests were conducted with a buried copper-iron ball corrosion system—to eliminate edge effects.

Evaluation of the test data and fundamental considerations show: 1. Short lines of corrosion current continue to flow at the anode-cathode boundary even though the net closure circuit current flow is made zero. 2. Short lines of corrosion current continue to flow even though there is no current flow through the soil shown by a McCollum Earth Current Meter. 3. To stop short lines of corrosion current flow, the potential of the pipe measured against a reference electrode must be made increasingly more electro-negative when the reference electrode is positioned further from the pipeline. 4. In a mixed (anodic-cathodic control) corrosion system, the "apparent" break in the pot.-log c.d. relation is not a reliable indication of protective current requirements.

The study is directed toward criterion requirements for approaching "complete" rather than "adequate" cathodic protection.

5.2.4

Introduction

Minimum criteria for the measurement of complete protection on buried pipelines are needed by the corrosion engineer to meet his increasing responsibility to assure public safety and, in some instances, to prevent major economic loss from pipe penetration or rupture.

In the absence of a universally accepted criterion for complete cathodic protection of pipelines, several criteria are used, among the more common of which are:

1. Pipe to reference electrode potential
   a. electrode remote
   b. electrode on ground over pipe
   c. electrode close to pipe
2. Measurement of current flow into the pipeline with the McCollum Earth Current Meter.
3. Change in the pipe-to-reference electrode potential of 200 to 300 millivolts.
4. The "apparent" break in the pot.-log c.d. relation.

The authors have observed that while these criteria often indicate "adequate" protection, leaks sometimes continue to occur, usually at a lower rate, even though the minimum requirements of most of the criteria have been met.

Much work has been done by many investigators to determine reliable criteria which will show that corrosion has been stopped by the application of cathodic protection. However, most of this work has been done in the laboratory, and from the standpoint of practicability, no one reliable criterion which can be used under all conditions in the field has been agreed upon. In nearly every technical meeting, the burning question arises, "How do you decide upon the current required for cathodic protection?"

This is not an indication of lack of appreciation by the investigators of the field engineer's problem. Rather, it might be an indication that some of the important factors involved are being ignored in the field and that attempts are being made to over-simplify an inherently complex situation.

The objective of this paper is to compare on a model pipeline corrosion system which embodies some of the possible geometric and environmental conditions the criteria commonly used. It is hoped this paper will lead to better understanding of the relationship between the pipeline corrosion mechanism and the meaning of the cathodic protection criterion used.

Background

Although the cathodic protection principle is well known and has been used increasingly during the last 25 years to control corrosion on pipelines, it is noted that many engineers place great reliance on some single criterion or empirical value to indicate the protective state.

The resulting opinions made in an analysis of 136 replies to a Questionnaire[1] prepared in 1948 by National Association of Corrosion Engineers Committee T-4 (now T-2C) "to ascertain whether or not there was any proven procedure for determining the effectiveness of cathodic protection" showed:

1. There was no single thoroughly proven criterion for cathodic protection of pipelines used for all conditions.
2. Minimum current requirements probably are variable from place to place and from time to time.

In the 79 replies describing the criteria used, there were at least 24 different procedures or values of potential, current or reference electrodes mentioned.

A survey in 1953 by the American Gas Association[2] on criteria for protection of bare pipelines show no more unanimity in the methods used by the utility industry. Reference electrode locations for measuring protective potential are reportedly over the pipeline and at distances from 5 to 400 feet away.

A comprehensive survey of the three general forms of cathodic protection criteria a) current density, b) pipe-to-soil potentials and c) current potential curves used on pipelines prior to 1945 was made by Logan.[3]

More recently, Logan[4] compared four cathodic protection criteria on pipe sections 7 inches in outside diameter (80 to 120 feet in length) buried in high (16,000 ohm cm) and low 90-230 ohm cm) resistivity soils. In high resistivity soils, wide disagreement in current requirements was found between a) the "apparent" break in the "null" pot.-log c.d. relationship b) pipe potential change of .3 volt c) pipe potential of —.85 volt to a $CuSO_4$ reference electrode over the pipe and d) —.85 volt to a remote $CuSO_4$ reference electrode. It was recommended that this disagreement among the criteria used should be investigated.

The public utility commissions of at least seven states have become concerned with the possible hazards of high pressure transmission lines through residential areas and have prepared regulatory codes which include provisions for protective coatings and other corrosion control methods. It is inevitable that further development of these codes will be aimed at assuring complete corrosion control. The NACE statement on Minimum Requirements for Protection of Buried Pipelines[5] indicates that some reliable criterion for cathodic protection must be established.

Test Pipe Line

Through the efforts of O. W. Wade, Chief Corrosion Engineer for the Transcontinental Gas Pipe Line Corporation, his company laid 240 feet of bare 6-inch pipe with welded joints at a remote location (Figure 1). The nearest underground structure is a 1-inch water line approximately 800 feet away. The line was laid in level terrain at a depth of three feet and the soil was well tamped during the backfilling.

The resistivity of the soil in which the pipe was buried varied from 22,000 to 55,900 ohm. centimeters at 1-foot depth (soil box measurement); 16,100 to 37,000 ohm. centimeters at a 3-foot pin spacing (four pin measurement); and from 20,300 to 44,700 ohm. centimeters at a 6-foot pin spacing.

Insulating flanges were placed in the line 100 feet from each end in order

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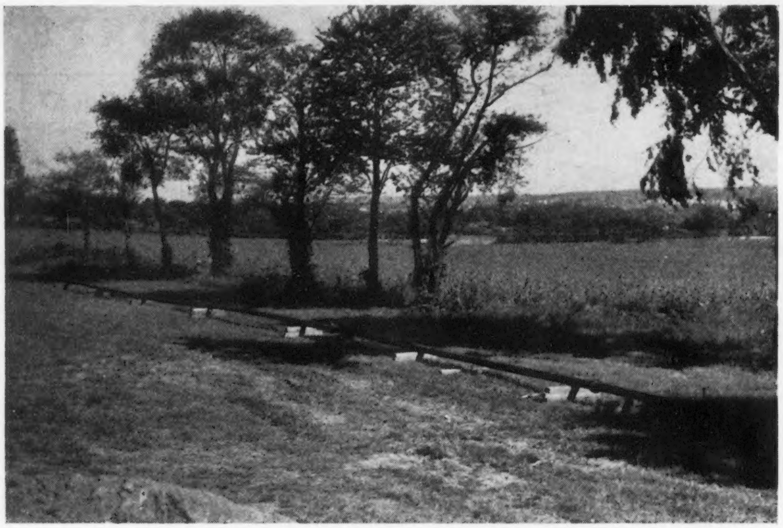

Figure 1—Assembled test pipeline at site before burial.

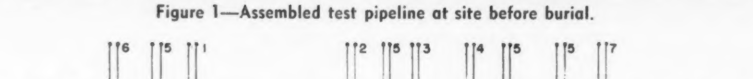

Figure 2—Pipeline cathodic protection criteria test arrangement.

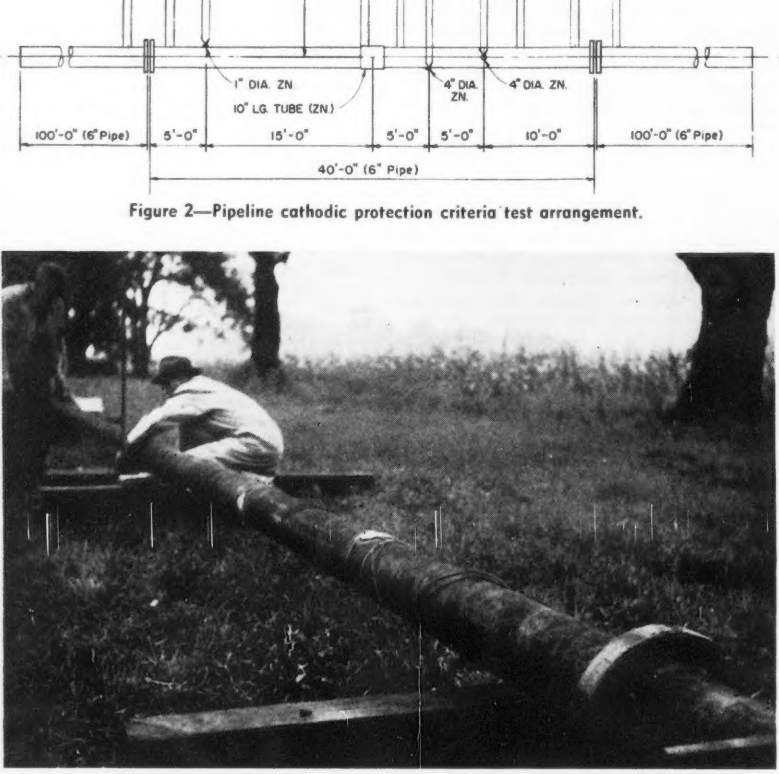

Figure 3—Zinc (representing anode areas) secured to pipe.

that the current collected on the 40-foot center section could be measured and end effects minimized. Test lead wires were attached to each of the three isolated sections (Figure 2). A 1-inch diameter, $\frac{3}{16}$-inch thick zinc disk (anode No. 1) was secured to the top of the pipe five feet from the west end of the 40-foot center section. The insides of all zinc anodes were covered with polyethylene tape to insulate them from the steel pipeline. In the center of the 40-foot pipe section, a sheet of the zinc 10 inches wide (anode No. 2) was placed completely around the pipe and insulated from it (Figure 3). Four-inch diameter zinc disks were also placed on the 40-foot section (anode No. 3), one on the bottom 25 feet from the west end and one (anode No. 4) on the side 30 feet from the west end. The anodes were of high purity zinc (.009% Pb and .0003% Fe) which was supplied by the New Jersey Zinc Company. The two test lead wires secured to each zinc anode were brought above ground to allow measurement of the closure circuit current and potential. A 20-foot piece of 6-inch pipe was buried vertically in the earth approximately 500 feet north of the test pipeline to serve as a ground bed for cathodic protection current.

Preliminary Measurements—Zinc Anodes

Before the zinc anodes were connected to the pipe and thus allowed to generate current with possible resulting polarization, the voltage between each of them and a copper-copper sulfate reference electrode was measured. This was on October 13, 1955. On September 21, 1956, these measurements were repeated on anodes No. 1 and 2, with the results shown in Table 1.

When the anodes all were connected to the pipe through ammeters, the values of anode, or corroding currents measured as shown in Table 2.

The internal resistance between anodes and pipe was measured with the results shown in Table 3.

The internal resistance of the west insulated flange was found to be 53.2 ohms, and of the east flange, 35.0 ohms.

Surface Potential Profile

A type of corrosion survey known as the surface potential survey is widely used as an attempt to locate anodic areas on a pipe line by making use of the fact that current flowing from pipe to earth and then through the earth into the pipe at cathodic areas, produces an IR drop through the earth. This effect

TABLE 1

Anode	10-13-55		9-21-56
	11:00 am	4:30 pm (After Testing)	
1	—1.06 V.	—1.03 V.	—1.03 V.
2	—1.08 V.	—1.02 V.	—1.05 V
3	—1.04 V.	—1.03 V.	....
4	—1.11	—1.05 V.	....

TABLE 2

Anode	Milliamperes
1	.0388
2	2.85
3	.230
4	.365

TABLE 3

Anode	Ohms
1	14,100
2	263
3	2,890
4	2,170

is measured at the ground surface by placing two reference half cells over the pipe at from approximately 25 to 100 feet apart. By observing the polarity of the potential difference between the half cells, the direction of current flow through the earth is determined. One half cell is then placed at the same distance beyond the other and a new reading taken. The survey is continued in this manner through the area of interest and the readings obtained are then plotted against distance. The comparative slopes of the graph segments are interpreted as providing a means of locating anodic areas on the line.

In order to determine ground surface potential gradient effects from representative anodic areas on a pipeline, measurements of the voltage change between the pipe and a $CuSO_4$ reference electrode placed on the ground surface directly over the pipe were taken while the circuit between each zinc anode and pipe was opened and closed individually. Prior to this testing, voltage readings between the pipe and reference electrode were taken with all anodes open and with the reference electrode placed directly over the pipe at 2.5-foot intervals along the 40-foot central section. The results are shown as "Anodes Open" in Figure 4. The reference electrode was then placed directly over a zinc anode and readings between pipe and half cell were taken while the circuit between anode and pipe was opened and closed. This process was repeated with the reference electrode placed over the pipe at 2.5-foot intervals along the 40-foot pipe section.

These results corroborate recent work[6] conducted on a pipeline in a uniform environment. They indicate that, while large anodic areas which produce more long line currents can be located, the surface potential survey will not sense small anodic areas such as those which may be caused by small pieces of clay contacting the pipeline in a sandy backfill.

Earth Current Meter

The measuring, or sensing, element used for earth current measurements is called a cantilever electrode. This consists of a narrow strip of micarta at each end of which are mounted two small $CuSO_4$ reference electrodes spaced (4½) inches apart. Mounted between them are two metal soil contact electrodes. The cantilever electrode is placed in the soil at the pipe surface and perpendicular to it and leads from the two reference electrodes and two metal contacts are brought above ground to the measuring instrument. The reference electrodes are used for potential gradient measurement and the metal contacts enable measured current to be impressed in the earth surrounding the reference electrodes. While this current is turned on and off, simultaneous readings are taken of the resulting change in gradient. The data are used to calculate current density entering or leaving the pipe surface.

Figure 5 shows the various positions in which the earth current meter electrode was placed over zinc anodes Nos. 1 and 2 in order to compare earth current meter indications with readings of a milliammeter connected in the closure circuit between zinc anode and pipe. Protective current was applied until the current shown by each meter was zero.

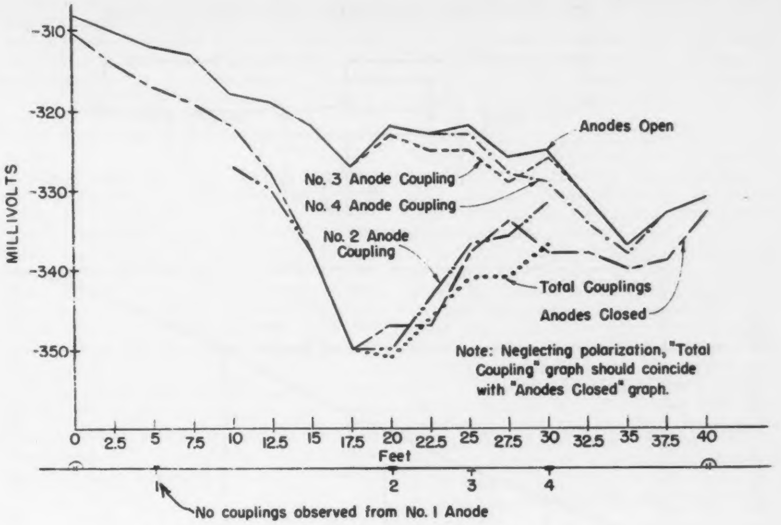

Figure 4—Surface potential survey.

Table 4 shows the results obtained from these tests.

These data indicate that corrosion current continues to flow even though the earth current meter shows that corrosion current has ceased. For example, with the electrode in position 3 over Anode No. 2, the anode current with no cathodic protection current was 3.30 milliamperes. With a cathodic protection current of 58 milliamperes, the earth current meter indicated that corrosion of the anode was stopped. Actually, the corrosion current had been decreased only 58 percent. It was necessary to increase the protection current to 98 milliamperes in order to stop the net corrosion current flow shown by the closure circuit milliammeter. At this stage, the earth current meter indicated the anode to have become cathodic by virtue of the reversal of current flow through the soil into the pipeline.

The concept of corrosion current flow line distribution in an anode-cathode system discussed later (see Figure 13) becomes helpful to explain this situation. Since the net closure circuit corrosion current flow had been decreased by only 58 percent when the earth current meter indicated no corrosion current flow, the remaining 42 percent of the corrosion current must have flow lines whose maximum trajectory is less than the span of the ECM electrode. When the net closure circuit corrosion current flow is made zero, the earth current meter indicated current flow into the anodes. Since the closure circuit milliammeter must show all current interchange between the anode and cathode, the difference in current shown by the earth current flowing into the anode and the closure circuit milliammeter could only be short line corrosion current flow from anode to cathode at their junction.

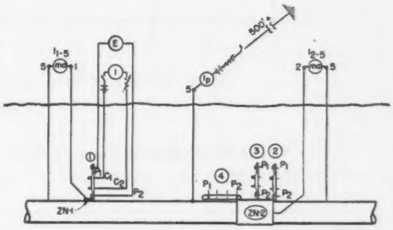

Figure 5—Comparison of closure circuit and earth current meter corrosion current flow measurements.

Test data at Electrode Position 4 support the superposition theory (i.e., there was only slight change in potential between anode and cathode parallel to the pipeline when adequate protective current is applied normal to the pipeline to reduce the net anode closure circuit current flow to zero).

The earth current meter observations were made with an instrument furnished and operated by W. Luttrell, of the Texas Eastern Pipeline Company.

TABLE 4

Zinc Anode	Earth Current Electrode Position	Cathodic Protection Current, Ma	Anode Current Ma.	E.C.M. Electrode Potential (Mv)*
1	1	0	.054	+ 33.9
1	1	15.9	.0518	— 3.0
2	2	0	3.45	+200
2	2	58	1.45	0
2	3	0	3.30	+199
2	3	58	1.40	0
2	3	98	0	—132
2	4	0	3.35	+225
2	4	95	0	+240

* (+) Indicates corrosion current flow from anode.
(—) Indicates cathodic protection current into anode.

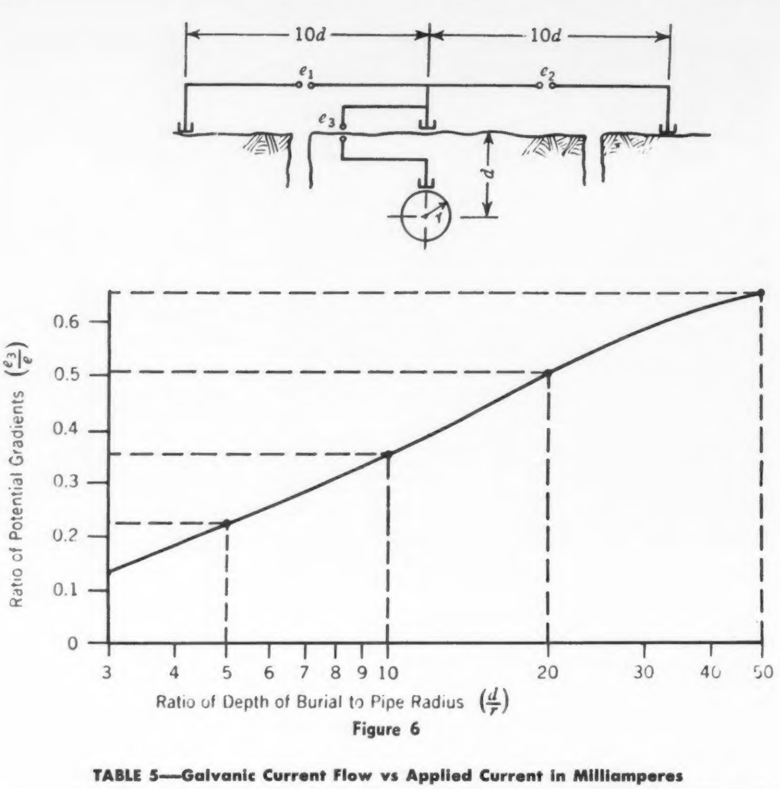

Figure 6

TABLE 5—Galvanic Current Flow vs Applied Current in Milliamperes

I_p	0 ma	598 ma	916 ma	1100 ma	1280 ma
I_1-5	.044	.023	.0107	.0047	.00
I_2-5	2.40	.00	—1.30	—1.92	—2.55
I_3-5	.27	.095	.00	— .048	— .090
I_4-5	.38	.067	.024	.00	— .023

TABLE 6

Zinc Anode	Potential vs $CuSO_4$ (Volts)
1	—3.85
2	—2.04
3	—2.68
4	—3.11

McCollum and Logan[7] discussed the practical limitations of the earth current meter ". . . under favorable circumstances, it is possible to pick up, with a 4½-inch contactor, evidences of current flowing between a corroded and an uncorroded point on a section of a pipe, providing the path of this current is long enough to include both the potential terminals of the electrode. However, the contactor picks up but a component of this current and it is not possible to compute the true galvanic current from the reading obtained. If the galvanic circuit is very short, as is often the case, the earth current meter will be only slightly affected, if at all."

Net Closure Circuit Anode Current Flow

The net current flow was measured between each zinc anode and the steel pipeline while increasing amounts of protective current was applied. It was noted that less protective current was required for the larger zinc anodes. This may be attributable to high proportion of long lines of corrosion current flow for the larger anode where the ratio of area to periphery is greater.

Potential Measurements—Protected Pipeline

The potential of the pipeline was measured against a $CuSO_4$ reference electrode placed on the ground surface over each zinc anode when the net anode current flow was made zero by application of cathodic protection current.

The potential measured at the ground surface was more electronegative than the open circuit potential of the zinc (see Table 1) and most electronegative for the smallest zinc anode.

When 1480 ma of protective current was applied to the pipeline, the potential of the pipeline to a $CuSO_4$ reference electrode located 250 feet south was —22.0 volts (the anode bed was north of the pipeline). These results indicate that the potential of the pipeline against a reference electrode must be made increasingly electronegative as the reference electrode is located farther from the pipeline if all corrosion current flow lines are to be completely controlled.[6]

Subsurface Potential Calculations

It is difficult to measure the potential of the pipe to a reference electrode positioned close to its surface. The potential of a bare pipe in a uniform environment to a close reference electrode can be calculated from ground surface potential measurements. Because environments surrounding a pipeline are not ordinarily uniform, the following observations are helpful in providing an approximation of the current received by the pipeline and of the IR drop between the reference electrode and the pipeline.

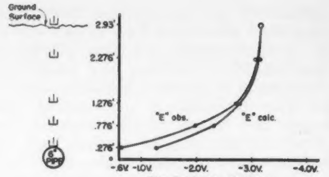

Figure 7—Potential gradient observed, pipe to ground surface.

Howell[8] showed that the current collected (I) per linear foot of pipe can be calculated from the ground surface gradient normal to the pipeline, as follows:

$$I = \frac{42_e}{\rho} \qquad (1)$$

in which 'e', the average surface voltage drop (mv) for spacing of ten pipe depths normal to the pipeline, is equal to

$$\frac{e_1 + e_2}{2}$$

Pearson[9] proposed a similar development measuring the potential drop over a distance equal to about 3x the depth of burial.

The potential of the pipe surface to the close reference electrode is expressed as follows:

$$E_r = E_s + 0.5_e\left(\log\frac{d}{r} - \log\frac{2d-r}{d}\right) \qquad (2)$$

in which: E_r is the pipe-to-reference electrode potential at a distance 'r' (ft.) from the pipe axis (mv).

E_s is the pipe-to-reference electrode potential over pipe at the soil surface (mv); ρ is soil resistivity (ohm-cm) and 'd' is the depth of burial (ft.)

The relationship between the ratio of potential gradients e_3/e to the ratio of the depth of burial to the pipe radius developed by use of Equations (1) and (2) and shown in Figure 6 was applied to the pipeline.

Total current applied to the pipeline was 1380 ma. The 40-foot section received 1380 — 1126 = 254 ma.

$$I_{act.} = \frac{254}{40} = 6.35 \text{ ma/lin. ft.}$$

The average potential gradient 'e' normal to the pipeline was

$$\frac{e_1 + e_2}{2} = \frac{5570 + 3090}{2} = 4330 \text{ mv.}$$

The soil resistivity	ohm cm
5 feet north of pipeline	16,100
Over pipeline	34,600
5 feet south of pipeline	24,200
Average	24,900

$$I_{calc.} = \frac{42_e}{\rho} = \frac{42 \times 4330}{24,900} = 7.30 \text{ ma/lin. ft.}$$

The relationship between calculated and observed pipe to reference electrode measurements are shown in Figure 7. In this test

$$\frac{e_1 + e_2}{2} = \frac{6200 + 3920}{2} = 5060 \text{ mv.}$$

Since calculated and observed measurements have correlated closely on a test pipe section in a uniform environment[8] it is felt that the non-uniformities of the soil account for most of the variation between observed and calculated values of potential gradients and the current received by a lineal foot of pipeline.

Potential Current Relationships

While applying current to iron in aerated 0.1 N KCl solution, Evans, Bannister and Britton[10] found that the potential of the metal did not change until there was adequate protective current to control corrosion. This observation has encouraged fundamental studies for an indirect method of determining the minimum current required for complete corrosion control.[11, 12, 13, 14]

In corrosion systems under cathodic control, the potential of the cathode, polarized by the corrosion current, approaches the potential of the anode i.e., $E_m \cong E_a$.[15, 16] When increasing amounts of protective current are applied, the metal potential remains nearly constant until current discharge at the anode ceases and a cathode process occurs. Since the overall electrode process then becomes the evolution of hydrogen the potential of the metal E_m varies with the logarithm of the current.

Pope[17] has used polarization diagrams to show the effects of certain cell characteristics on the cell current and the minimum cathodic protection current required to stop corrosion. In the special case of cathodic control, the corrosion current and the protective current requirements are equal. In the practice of applying cathodic protection, this characteristic of cathodic control is seldom experienced, particularly in high resistivity, well aerated environments where a mixed control (anodic-cathodic) corrosion system occurs. For example, on a pipeline in high resistivity soil, the corrosion current flow from a few local anodes may not be adequate to reduce all the O_2 reaching the cathode surface. The potential of this pipeline, seen by a reference electrode on the ground surface, is quite noble. The initial "apparent" break in such a potential-log current relationship may be attributable to a transition from oxygen reduction to hydrogen evolution on the cathode areas with no meaningful change having occurred in the process at the anode. In the more conductive environments where the corrosion current flow is not appreciably restricted by the electrolyte resistivity, cathodic control will be approached and the "apparent" break may be more closely related to the minimum current requirement.

The corrosion system most frequently found on pipelines in high resistivity soils more closely approaches the "macroscopic" cell described by Waber[18] where the corrosion is controlled mainly by the resistance of the corroding media. "Microscopic" cell corrosion is controlled mainly by polarization. Thus, it should be difficult to relate polarization data obtained on a sandblasted specimen (microscopic cell) with that obtained on a pipeline where the "macroscopic" corrosion cell may be the prevalent form of corrosion.

In reviewing the studies[14, 11, 19] where mixed control corrosion systems exist, it is difficult to relate the current at the "apparent" break with the minimum current required for protection. In some of the controlled experiments[14, 11] the current applied at the "apparent" break was either much greater or less than the current needed to control corrosion after a period of several days. In a galvanic corrosion system,[19] the protective current required to stop corrosion current flow was greater than the current applied at the "apparent" break. Under conditions approaching cathodic control[20] the corrosion rate was calculated from the cathodic "polarization" curve.

Mears and Bialosky[21] point out that the correspondence of the "apparent" potential break with limiting current density demonstrated by Evans, Bannister and Britton[10] is a special case and not a true generalization. In a discussion, Mears[21] has indicated that whenever the local anodes polarize appreciably, the protective current will be higher than the current indicated by the "apparent" break.

Stern and Geary[22] have suggested that the introduction of "breaks" into a polarization curve requires a great deal of "imagination". Changes in slope rather than a sharp break occur when two or more different rate determining reactions occur.

It has been noted that an "apparent" break may be obtained by plotting a linear potential-current data on semi-log paper. Such data have been used mistakenly with faith.

The authors feel that the use of the "apparent" potential break as a criterion for minimum current requirements is not a reliable method except for corrosion systems approaching or under complete cathodic control.

In order to detect changes in potential on the cathodically protected surfaces when increasing amounts of protective current are applied, it is helpful to eliminate the IR drop effect between the observing reference electrode and the structure caused by the protective current. Pearson[12] and Holler[23] have devised "null" circuits by which the IR drop resulting from the applied current are compensated for. The Pearson "Null" circuit (Figure 8) essentially consists of a Wheatstone Bridge which uses the resistances through the environment be-

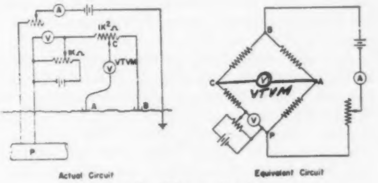

Figure 8—The null circuit.

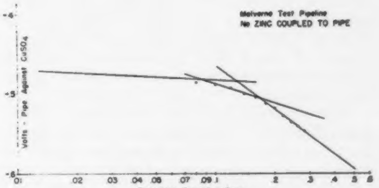

Figure 10—Pipeline polarization.

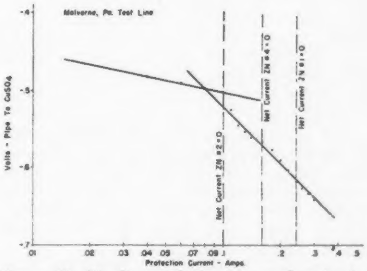

Figure 9—Pipeline polarization and net zinc anode current flow.

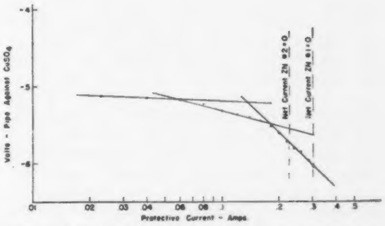

Figure 11—Pipeline polarization and net zinc anodic current flow.

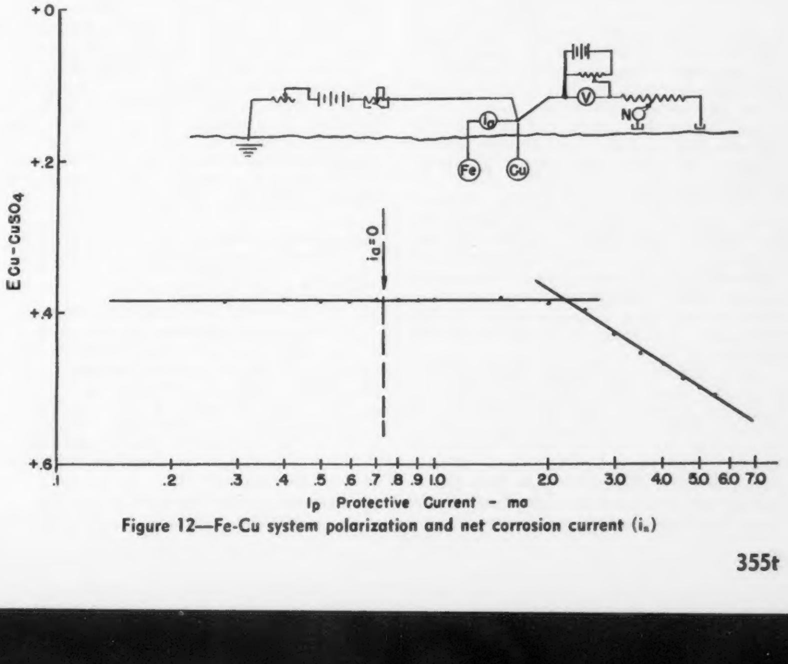

Figure 12—Fe-Cu system polarization and net corrosion current (i_a)

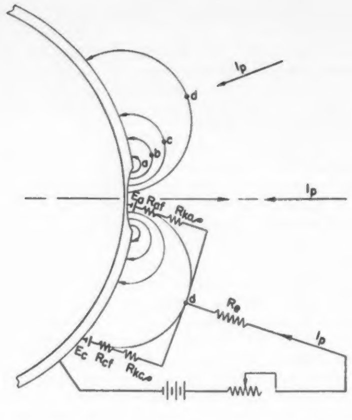

Figure 13—Corrosion current flow lines and equivalent cathodic protection circuit.

tween the structure and observing electrodes as two legs of the bridge. The protective current is varied by about 10 percent in order to observe its effect separately from the corrosion current effects. The "null" circuit or bridge is balanced until the incremental change in protective current has no effect upon the structure potential observed.

The potential of the structure is observed after a regular interval (3 minutes is often found adequate) and the next larger increment of protective current is then applied. A "polarization" curve is developed by plotting the voltages against the logarithm of the protective current.

Several "polarization" curves were established on the test pipeline while simultaneous observations were made of the protective current required to stop the net anode current flow in the zinc-pipe closure circuit. In Figure 9, the protective current required to stop the net anode closure circuit current flow for zinc anodes 2, 4 and 1 respectively became increasingly greater and exceded the protective current required to produce an "apparent" break in the "polarization" curve. Nearly a year later, the "polarization" curves (Figures 10 and 11) were prepared.

Because it has been shown (earth current meter) that short lines of corrosion current flow at the edge of a zinc anode, even though the net anode closure circuit current flow is made zero, the protective current flow required to stop all corrosion current flow is greater than any of the indicated values.

In Figure 10, made before the zinc anodes were coupled to the pipe and in Figure 11, three separate "apparent" breaks may be identified.

On two testing occasions, "sheet" stray current effects made it impossible to balance the "null" circuit. Logan[4] pointed out that "null" techniques require special equipment and are liable to errors which may result from the multiplicity of batteries, instruments, adjustments and extraneous stray current effects.

In an effort to eliminate edge effects, a buried copper-iron ball corrosion system was studied with the assistance of Robert Pope in Quakertown, Pennsylvania. The 4—5-inch diameter balls were buried about 18 inches apart and 24-inch depth in high resistivity soil. The polarization data are shown in Figure 12. The net anode closure circuit current flow i_a becomes zero before the "apparent" break in the polarization curve. The long lines of corrosion current flow in the copper-iron ball corrosion system are more easily controlled than the short lines found in the corrosion system at Malvern, Pennsylvania.

In an intentionally unbalanced "null" polarization study, it was found possible to develop an "apparent" break in a "polarization" curve, which became more noble as the protective current was increased.

Criteria of Protection

Theoretically, the minimum criteria for complete control of electrochemical corrosion by cathodic protection must indicate that a) no current flows out of the metal surface into the electrolyte or b) the cathode has been polarized to the open circuit potential of the anode.[15] Criteria expressed in thermodynamic or equivalent electric circuit systems alone do not adequately explain the requirements for the practical measurement of the protective state on a pipeline. Evans[24] has suggested that the physical chemist finds a strangeness in corrosion phenomena ". . . where geometry and not energetics controls the situations. . .".

An equivalent circuit concept[6, 25] has been proposed to show the relationship between the reference electrode position in measuring the potential of a corrosion system and the individual lines of corrosion current flow. This concept which considers the geometry of a corrosion system and includes the superimposed effects of impressed current on a pipeline is shown in Figure 13.

The distribution of equipotential lines in the electrolyte surrounding the corrosion system can be resolved into lines of current flow.[26] Such lines of corrosion current flow are normal to the equipotential lines and have the following spatial characteristics:

1. Corrosion current flow lines are normal at the metal surface and do not cross each other.
2. Corrosion current flow lines are shortest at the anode—cathode junction.
3. In localized pitting, the ratio of periphery to area is greater than for larger corrosion systems. A greater proportion of short lines of corrosion current flow occur in localized pitting.

The relationship of potential and resistance in a single corrosion flow line (ex. flow line "d" Figure 1) can be expressed by use of Kirchoff's Laws. The electrical elements in the corrosion current flow line are:

E_a — anode potential (E'_a — f (i_a/A_a), t
E_c — cathode potential (E'_c — f (i_c/A_c), t
i_a — anode current
i_c — cathode current
$R_a = (R_{af} + R_{ka}\rho)$ — resistance component of anode film and electrolyte to flow line boundary "d" normal to metal surface.
$R_c = (R_{cf} + R_{kc}\rho)$ — resistance component of cathode film and electrolyte to flow line boundary "d" normal to metal surface.
R_e — resistance of electrolyte outside boundary "d"
i_L — local action current
I_p — protective current

The local action current flow is expressed:

$$-E_a + E_c + i_L R_a + L R_c = O \quad (3)$$

$$i_L = \frac{E_a - E_c}{R_a + R_c} \quad (4)$$

The metal potential E_m measured against a reference electrode positioned at the electrical boundary of the corrosion current flow line "d" includes the effect of the resistive components R_a and R_c. (Electrical boundary of a single corrosion current flow line is located at the maximum distance of the trajectory from the anode-cathode system).

$$E_m = E_a - i_a R_a = E_c + i_c R_c \quad (5)$$

The corrosion system is under cathodic control[16, 27] where:

$$E_m \cong E'_a$$
(open circuit potential of anode)
(6)

The corrosion system is under anode control where:

$$E_m \cong E'_c$$
(open circuit potential of cathode)
(7)

Since the potential E_m observed at "d", particularly in high resistivity soils, lay between E'_a and E'_c the corrosion system on pipe lines is usually under mixed (anodic-cathodic) control.

When protective current is applied, the superposition effect of the current may be shown as follows:

$$+ i_c - i_a - I_p = O \quad (8)$$

$$\left.\begin{array}{l} i_a R_a + i_c R_c = -E_c + E_a \\ -i_a + i_c = I_p \end{array}\right] \begin{array}{ll} \text{multiply by 1} & (9) \\ \text{multiply by } R_c & (10) \end{array}$$

$$i_a (R_a + R_c) = E_a - E_c - I_p R_c \quad (11)$$

$$i_a = \frac{E_a - E_c}{R_a + R_c} - \frac{R_c I_p}{R_a + R_c} \quad (12)$$

By definition, cathodic protection is complete when:

(a) $i_a = 0$ (no current flows out of anode) or
(b) $E'_a = E_c + I_p R_c$ (the cathode has been polarized to the open circuit of the anode E'_a)

There can be no net corrosion current flow at the anode along line "d" if the potential at point "d" is equal to the open circuit potential of the anode E'_a. The polarized potential of the cathode includes E_c plus the $I_p R_c$ drop from point "d" to the pipe surface. The corrosion current flow line "d," being entitled to longer soil path potential drop than corrosion current flow lines "a," "b" and "c," will be polarized to the protective potential E'_a first. Some corrosion current will continue to flow along lines "a," "b" and "c" until the protective potential is observed at their respective electrical boundaries.

Miller[28] has shown that flow of corrosion current between dissimilar metal pipe sections spaced 12 to 45 feet apart is controlled when the open circuit potential of the anode is observed at a remote location. In this case of long lines of corrosion current flow, the cathode polarization is entitled to most of the IR drop through the soil between the remote reference electrode and the corroding system.

More recently, Schwerdtfeger and

Denison[29] have shown that the reference electrode must be placed within a few pipe diameters to measure the protective potential in order to stop the net corrosion current flow in their bimetallic corrosion system.

It has been generalized[6] that:

> Long lines of corrosion current flow are controlled when the protective potential E'_a is measured against a reference electrode at a remote location. The effects of shorter lines of corrosion current will be reduced.
>
> In order to stop short lines of corrosion current, the protective potential E'_a must be observed against a reference electrode placed at the metal surface.

Protective Potential

Nearly 25 years ago, Kuhn[30] indicated the optimum protective potential of steel pipe to a $CuSO_4$ reference electrode is —.85 volt. While there has been general acceptance of this protective potential value, there has been little consideration given to the significance of the reference electrode position.[6]

Although the open circuit potential of a non-corroding anode has not been established clearly, it has been observed that the corrosion rate of iron in an airfree environment[31] at a pH of 9.0 is negligible.

Some of the concepts of the protective potential are:

Concept 1—An equilibrium single electrode potential must be defined in terms of concentration of metal ions. Wagner[32] says that in the absence of complex formation or precipitation of slightly soluble compounds, the anode current density is found to be negligible from a practical point of view if the metal ion concentration at the metal surface is less than 10^7 gram ion/liter. The equilibrium single electrode potential of a divalent metal is 0.2 volts more electronegative than the standard unit activity single electrode potential.

Example: $Fe \rightarrow Fe^{++} + 2e$

$$\text{S.H.E.} = —.44 \text{ V.}$$

$$—.44 — (.2) — (.316) = —.956 \text{ V.}$$

against $CuSO_4$

Concept 2—The protective potential calculated from an iron surface saturated with Fe (OH)2 @ pH 9.0

$$K_{sp} \text{ of Fe (OH)2} = 1.64 \times 10^{-14} = (a_{FE^{++}})\,(a\,OH^-)^2$$

Nernst Formula

$$E = E_o + \frac{RT}{NF} \ln a_{Fe^{++}}$$

$$a_{Fe^{++}} = \frac{1.64 \times 10^{-14}}{(10^{-5})^2} = 1.64 \times 10^{-4}$$

$$\text{S.H.E.} = —.440 + \frac{.059}{2} \log 1.64 \times 10^{-4}$$

$$\text{S.H.E.} = —.440 + (—.112) = —.552 \text{ V.}$$

$$—.552 — (.316) = —.868 \text{ V.}$$

against $CuSO_4$

Concept 3—It has been shown that iron in airfree soils at a pH of 9.0[14] has a negligible corrosion rate at a potential of —.78 volts measured against a saturated KCl reference electrode. This is equivalent to —.85 volts measured against a $CuSO_4$ reference electrode. The potential of steel completely buried in Hudson River organic silt or immersed in airfree sea water[33] has been found, by one of the authors, to be —.77 volts measured against a saturated KCl reference electrode.

Concept 4—Some laboratory studies[34] have indicated that the protective potential of iron in anaerobic sulfate reducing bacteria environments may be —.95 volts measured against a $CuSO_4$ reference electrode.

Galvanic corrosion is viewed commonly as consisting of dissimilar metals coupled together in a corroding electrolyte. The open circuit potential between iron in airfree environment (anode) and magnetic iron oxide (mill scale or rust scale) in an aerated environment (cathode) has been shown to exceed one volt.[35] Recent studies[36] show that mill scale removed from the underlying iron in order to eliminate the effects of the iron-mill scale couple, is more cathodic than copper and requires more current for polarization. Thus the potential difference between the zinc anodes and the steel pipe is not an unusual representation of the potentials found in a corroding system.

Conclusions

In a mixed control (anodic-cathodic) corrosion system such as may be found on a bare buried pipeline in a well aerated high resistivity soil, the following observations are pertinent:

1. A small localized (for example, a differential aeration) corrosion cell will not be sensed by a ground surface potential survey. On a bare pipeline, such corrosion cells always must be suspect.
2. The corrosion current flow line concept[6] may be used to demonstrate that the protective potential must be measured to a reference electrode positioned on the pipe surface at the point of interest in order to be assured that the short lines of corrosion current flow are stopped.

The potential measured must be increasingly electronegative as the reference electrode is positioned further from the pipeline.

Only long lines of corrosion current flow will be controlled when the protective potential is measured against a reference electrode at a remote position.

3. The earth current meter will not indicate the control of corrosion current flow lines whose maximum trajectory from the pipeline is less than the span of the electrode contactor.
4. At the time of testing, the actual current requirements for the control of corrosion[13] are greater than that indicated by an "apparent" break in the potential-log current relationship. Changes in surface conditions of the cathode caused by the accumulation of ampere hour effects may result in over or under protection if the current at the "apparent" break is applied for several days or months.[11, 14]
5. A pipe potential change (say 200 or 300 millivolts) criterion will not be reliable if the protective potential does not exist in the electrolyte at the anode-cathode junction of a local cell. Edge effects and the geometry of anode-cathode arrangements must be considered when interpreting the relationship between closure circuit current flow and other criteria.

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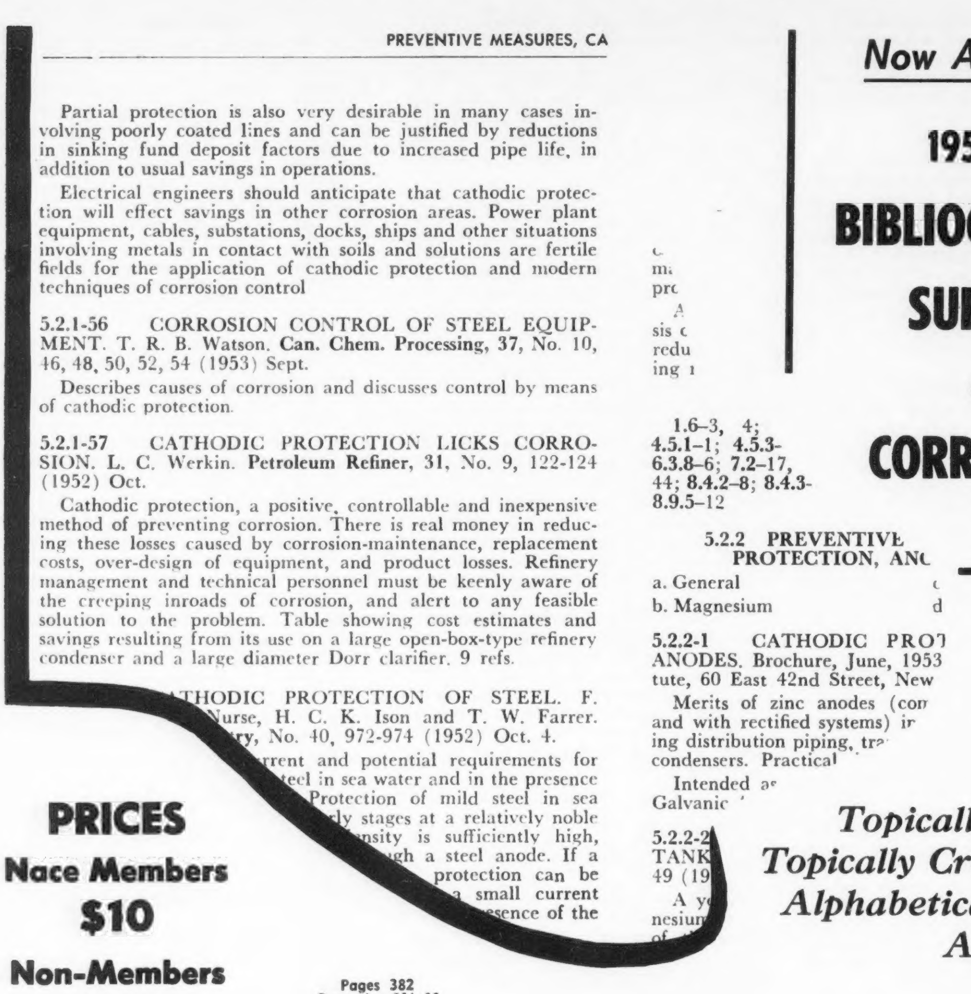

PREVENTIVE MEASURES, CA

Partial protection is also very desirable in many cases involving poorly coated lines and can be justified by reductions in sinking fund deposit factors due to increased pipe life, in addition to usual savings in operations.

Electrical engineers should anticipate that cathodic protection will effect savings in other corrosion areas. Power plant equipment, cables, substations, docks, ships and other situations involving metals in contact with soils and solutions are fertile fields for the application of cathodic protection and modern techniques of corrosion control

5.2.1-56 CORROSION CONTROL OF STEEL EQUIPMENT. T. R. B. Watson. **Can. Chem. Processing,** 37, No. 10, 46, 48, 50, 52, 54 (1953) Sept.

Describes causes of corrosion and discusses control by means of cathodic protection.

5.2.1-57 CATHODIC PROTECTION LICKS CORROSION. L. C. Werkin. **Petroleum Refiner,** 31, No. 9, 122-124 (1952) Oct.

Cathodic protection, a positive, controllable and inexpensive method of preventing corrosion. There is real money in reducing these losses caused by corrosion-maintenance, replacement costs, over-design of equipment, and product losses. Refinery management and technical personnel must be keenly aware of the creeping inroads of corrosion, and alert to any feasible solution to the problem. Table showing cost estimates and savings resulting from its use on a large open-box-type refinery condenser and a large diameter Dorr clarifier. 9 refs.

THODIC PROTECTION OF STEEL. F. Nurse, H. C. K. Ison and T. W. Farrer. ry, No. 40, 972-974 (1952) Oct. 4.

rrent and potential requirements for teel in sea water and in the presence Protection of mild steel in sea ly stages at a relatively noble nsity is sufficiently high, gh a steel anode. If a protection can be a small current esence of the

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1.6–3, 4; **4.5.1–1; 4.5.3-6.3.8–6; 7.2–17,** 44; **8.4.2–8; 8.4.3-8.9.5–12**

5.2.2 PREVENTIVE PROTECTION, AN

a. General
b. Magnesium

5.2.2-1 CATHODIC PRO ANODES. Brochure, June, 1953 tute, 60 East 42nd Street, New

Merits of zinc anodes (cor and with rectified systems) ir ing distribution piping, tr condensers. Practical

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TECHNICAL COMMITTEE ACTIVITIES

Six Major Committees Affiliate With T-7

Bellassai

Howell

New Jersey Group Affiliates With T-7A Northeast Region

The New Jersey Committee on Corrosion has affiliated with the NACE Group Committee T-7. The New Jersey committee will be under Unit Committee T-7A Northeast Region Corrosion Coordinating Committee. C. A. Erickson, Jr. is chairman of Unit Committee T-7A and of T-7.

Present officers of the New Jersey committee are: J. C. Howell, Public Service Electric and Gas Company, Maplewood, N. J.; S. J. Bellassai, Transcontinental Gas Pipe Line Company, vice chairman, J. A. Brower, Public Service Electric and Gas Company of New Jersey, secretary.

Operating companies interested in corrosion mitigation in New Jersey met first in January 1950 to discuss electrolysis conditions in the northern part of the state. At that meeting it was proposed that a corrosion committee be organized to deal with the mutual problems involved. The group further agreed that all companies having corrosion control programs would submit lists of cathodic protection installations, drainage bonds, electrolysis switches and interconnections.

In March 1954 the New Jersey Committee on Corrosion was organized formally with 43 members representing 30 companies. The committee has a good attendance record as indicated by the January 1957 meeting when 31 members representing 18 companies attended.

The committee operates as an information center for any company having underground structures. Because of the concentration of the facilities in the northern section of New Jersey practically 75 percent of committee activity is within the metropolitan area of New York City. The corrosion problems involved are of a local nature as are stray current problems arising from operation of six DC railway stations. Soil varies from tidal marsh land in the north to sand and gravel in the southern section of the state.

The committee holds three regular meetings yearly on second Tuesdays in

(Continued on Page 91)

Six major existing coordinating committees have affiliated with T-7 Corrosion Coordinating Committee since March, 1956. Five of these are under Unit Committee T-7A Northeast Region Coordinating Committee. Their officers are:

1. Charleston Coordinating Committee on Corrosion

F. W. Lloyd, United Fuel Gas Company, Charleston, West Va., chairman; K. R. Gosnell, Godfrey L. Cabot, Inc., Charleston, West Va., vice-chairman; H. W. Hetzer, West Virginia Water Service Company, Charleston, secretary.

2. The Greater Boston Electrolysis Committee

Elliott R. Perkins, New England Tel. & Tel. Co., Boston, Mass., chairman; K. E. Sawyer, Western Union Telegraph Co., Boston, vice-chairman; J. J. Molloy, Cambridge Electric Light Company, Cambridge, secretary.

3. Western Pennsylvania Coordinating Committee

F. E. Costanzo, The Manufacturers Light & Heat Company, Pittsburgh, chairman; G. C. Picht, Jr., American Tel. & Tel. Co., Pittsburgh, vice-chairman; C. A. Erickson, Jr., The Peoples Natural Gas Co., Pittsburgh, secretary.

4. Pittsburgh Corrosion Committee

C. M. Rutters, Equitable Gas Co., Pittsburgh, chairman; R. L. Smith, Duquesne Light Co., Pittsburgh, vice-chairman; E. W. Steel, The Bell Telephone Co. of Pa., Pittsburgh, secretary.

5. New Jersey Committee on Corrosion

J. C. Howell, Public Service Electric & Gas Company of New Jersey, Maplewood, chairman; S. L. Bellassai, Transcontinental Gas Pipe Line Company, Linden, N. J., vice-chairman; J. A. Brower, Public Service & Gas Company of New Jersey, Maplewood, secretary.

The committee in the South Central Region is:

1. Houston Corrosion Coordinating Committee

C. L. Mercer, Southwestern Bell Telephone Co., Houston, chairman.

T-7 anticipates many more corrosion coordinating committees will affiliate with the organization in the near future. The T-7 organization, including officers names and addresses is listed in the directory of NACE Technical Committees in this issue of Corrosion. The directory appears in six issues of Corrosion during each year. It is alternated with the directory of NACE Regions and Sections.

Wise and Segool Elected by Plastic Tape Committee

J. J. Wise, Arkansas Louisiana Gas Company, Shreveport, La. and H. D. Segool, the Kendall Company, Polyken Sales Division, Chicago, Ill. have been elected respectively chairman and vice-chairman of NACE Technical Unit

(Continued on Page 94)

GREATER BOSTON ELECTROLYSIS Committee members here examine Dec. 19, 1956 at Medford, Mass. a high silicon cast iron anode immersed in slightly salty water in a power manhole for 13 months while subjected to 1¾ amperes. Left to right: John T. Dyer, Suburban Electric Co. of Malden, Mass.; Vernon B. Pike, Bell Telephone Laboratories, Murray Hill, N. J. and Elliott R. Perkins, New England Telephone and Telegraph Co., chairman of the Boston committee.

Boston Committee Acts as Clearing House for Problems

Greater Boston Electrolysis Committee has recently affiliated with the NACE T-7 Corrosion Coordinating Committee. This was announced by C. A. Erickson, Jr., chairman of Technical Group Committee T-7.

Greater Boston Electrolysis Committee is located in the area of operation of Unit Committee T-7A Northeast Region Corrosion Coordinating Committee. Officers of the Greater Boston Electrolysis Committee are Elliott R. Perkins, New England Telephone and Telegraph Company, Boston, Mass., chairman; K. E. Sawyer, Western Union Telegraph Company, Boston, Mass., vice chairman; J. J. Molloy, Cambridge Electric Light Company, Cambridge, Mass. secretary-treasurer.

Although Boston was late in forming an official electrolysis committee, as such, when compared to such cities as Detroit and Pittsburgh, electrolysis is an old enemy in Boston. The first underground conduit for cables was laid in Boston in 1882 and seven years later in 1889 the first electric railway system was placed in service. Only two years after that the first cable failure occurred that could be attribued to the action of stray railway current.

Stray Current Is Interest

As means were developed for mitigating the effects for this stray railway current it became necessary for engineers and operating officials of the com-

(Continued on Page 90)

AT TECHNICAL COMMITTEE sessions during St. Louis conference: Left to right—Ward D. Sanford, Minnesota Mining & Mfg. Co., St. Paul, Minn., chairman of T-1J presides at the blackboard; at a meeting of T-3A, J. L. Wasco, Dow Chemical Co., Midland, Mich., chairman, left, presides; Charles P. Dillon, Carbide and Carbon Chemicals Co., Texas City discusses tanker corrosion at a session of T-6F at which W. S. Quimby, Texas Co., New York, presides.

Boston Committee—

(Continued from Page 89)

panies affected to work together in arranging for joint tests and corrective measures. As time progressed the engineers became interested in the joint problems, became known and well acquainted with each other and formed an unofficial committee.

Recent activity in the Metropolitan Boston area of several utilities using steel pipe lines for natural gas and petroleum products brought a concentration of underground structures providing a fertile field for multi-lateral interference problems which could be worked on jointly and simultaneously by the several utilities involved.

First meeting of the formal Greater Boston Electrolysis Committee was held in Cambridge, Mass. on August 31, 1953 to discuss mutual electrolysis problems associated with a new gas transmission line. A study of the gas transmission pipe line indicated that the line was draining up to 20 amperes to another pipe line in the vicinity and that this in turn was being returned to ground from man-made structures, apparently to the bottoms of steel storage tanks.

Electrolysis engineers of the gas transmission company considered it advisable to convene representatives of all companies whose properties might be affected by mitigation measures they might apply to their new pipe lines. Discussion indicated several companies were vitally interested in what was going to take place and that they would like to make their own tests and be advised of tests made by others.

Committee Was Logical

In view of the possibility of considerable inter-action of facilities described in cases discussed at the meeting it seemed desirable to some that a committee should be set up to discuss problems, testing programs and results and recommendations so that all would be informed as to what electrolysis mitigation and/or drainage systems were to be taken.

It was strongly urged that an electrolysis committee formed to consider and follow joint testing programs would prove more satisfactory to everyone concerned than a series of tests in individual companies. After considerable discussion it was agreed to write letters to designated officials of all companies represented at the meeting and to suggest that they appoint a representative to attend future meetings which would be called as the occasion required.

Official organization meeting was held October 29, 1953 when Boston and its vicinity and the encircling highway Route 128 was established as the sphere

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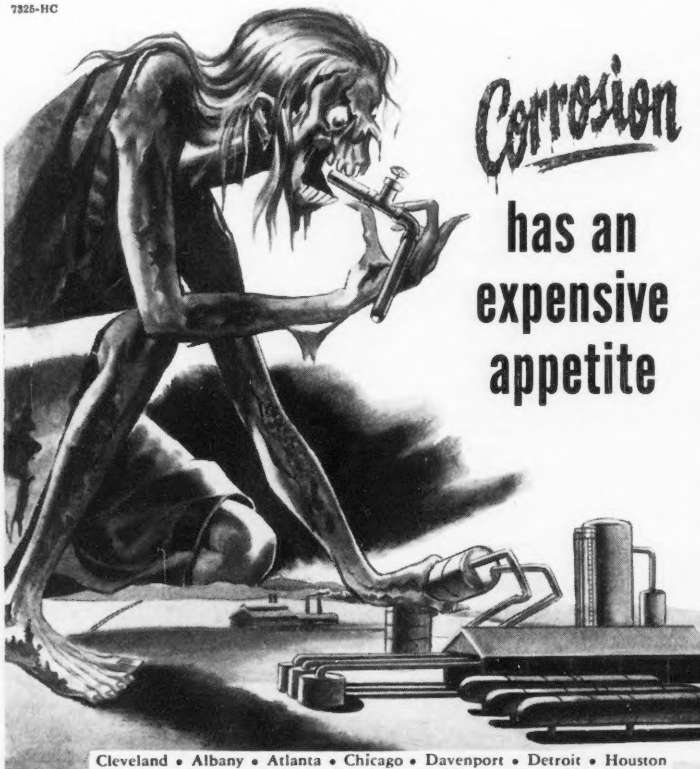

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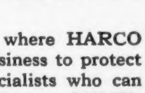

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OTHER TECHNICAL COMMITTEE sessions: left to right—T. E. Larson, Illinois State Water Survey, Urbana, Ill. chairman of T-4E is standing at left; at a session of T-7 C. A. Erickson, Jr., The People's Natural Gas Co., Pittsburgh, standing, chairman; seated, left to right J. M. Fouts, Koppers Co., Inc., Pittsburgh, past-chairman and T. J. Hull, NACE, Houston; W. P. Cathcart, Tank Lining Corp., presides at a meeting of T-6F.

of activities of the Greater Boston Electrolysis Committee.

In March 1954 a request was made of companies making up this committee for maps showing where their underground structures were located. Discussions were held regarding project notification forms and it was decided to adopt two kinds, one for a proposed installation of cathodic protection and another for a proposed installation of a drainage bond.

Acts As Clearing House

The Boston committee functions as a technical committee and constitutes a clearing house for the exchange of information on underground corrosion problems arising in the Greater Boston area. It does not undertake testing programs, engage in investigations, or make recommendations as a committee. Each member organization conducts such tests and surveys on its own property as it considers necessary and is the sole judge of its own requirements. A member organization may request from the members technical advice concerning its corrosion problems on an informal basis. A committee member may arrange with the chairman to place on the meeting agenda for discussion such corrosion problems that may be of particular interest to the committee as a whole. The committee acts as an agency by which members can be advised of planned installation of cathodic protection systems before installation so that interference tests can be conducted.

Members may be advised of completion of planned installation of corrosion mitigation systems when the final design or service date differs materially from the initial plan. They are advised of proposed installations of drainage bonds whether to another underground structure to the negative conductor of the traction systems so that interference tests may be conducted. They are advised of the abandonment or operation of any such system and they are advised of major additions to the through transmission facilities of the member's systems.

The Greater Boston Electrolysis Committee has prepared a brochure containing a complete history of the committee's organization and procedures, copies of which are available to groups forming similar committees in other metropolitan areas.

New Jersey Group—

(Continued from Page 89)

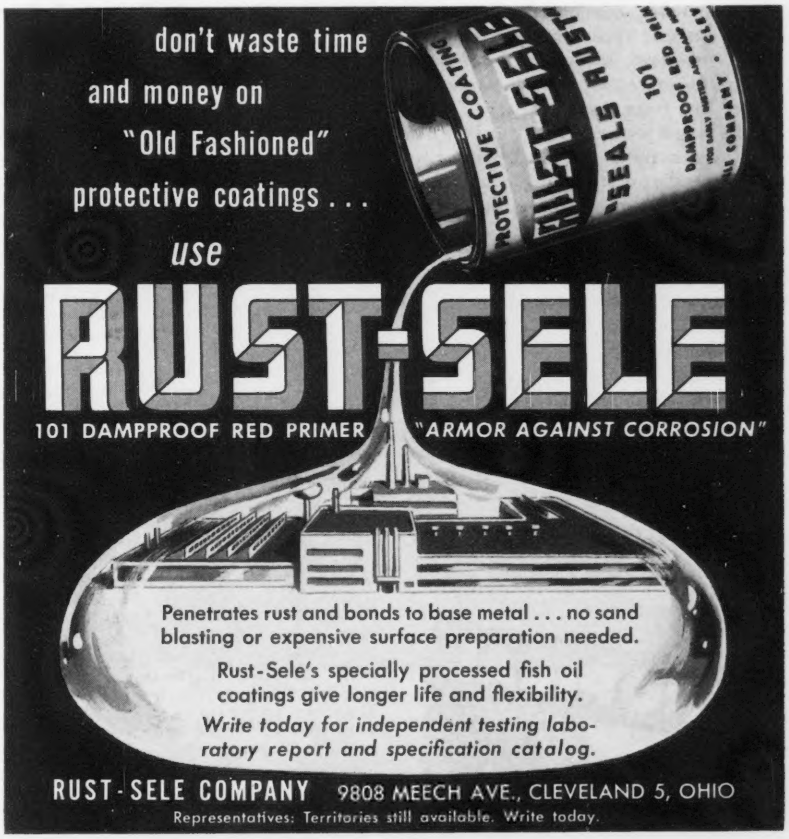
January, April and October. When required, special meetings may be called by the chairman. The committee neither undertakes testing programs nor engages in any investigation. It makes no recommendations.

Each member organization conducts tests and surveys on its own property it considers necessary and is the sole judge of its own requirements. However, a member organization may ask technical advice concerning its corrosion problems on an informal basis from the committee. A committee member may arrange with the chairman to place on the meeting agenda for discussion such corrosion problems as are of particular interest to his organization. The committee acts as an agency through which the members can be advised in advance, whenever possible, of such system changes as may be likely to influence the corrosion conditions on other systems. The secretary, when informed by a member company of an item of interest to all members, notifies all member organizations. Arrangements for joint testing, mitigation measures, etc. are made by direct negotiation between the member organizations concerned.

As a part of its formal organization the committee endorsed the procedures outlined in NACE publication entitled "Report of the Correlating Committee on Cathodic Protection" and recommended their use when practicable and applicable.

Thalmann Heads T-3D

E. H. Thalmann, Ebasco Services, Inc., New York, N. Y. has been elected chairman of NACE Technical Unit Committee T-3D on Instruments for Measuring Corrosion. Mr. Thalmann took office shortly before the committee's meeting held at St. Louis and presided at that meeting. The committee expects to start several new projects in connection with instruments used in measurement of corrosion. An announcement of new projects will be made when plans are complete.



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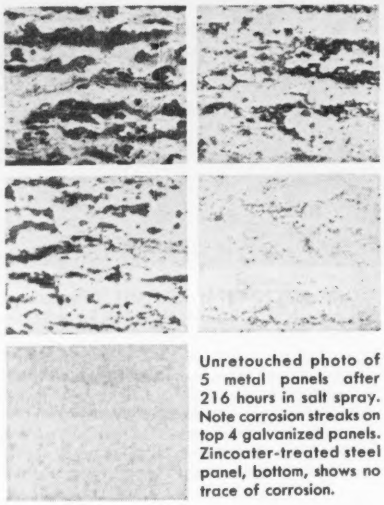

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Western Pennsylvania Corrosion Committee Affiliates With NACE T-7A Organization

Costanzo

C. A. Erickson, chairman of Unit Committee T-7A Northeast Region Corrosion Coordinating Committee has announced that the Western Pennsylvania Corrosion Committee has affiliated with NACE T-7. Officers of the Western Pennsylvania Corrosion Committee are: F. E. Costanzo, The Manufacturers Light and Heat Company, Pittsburgh, Pa., chairman; G. C. Picht, Jr., American Telephone and Telegraph Company, Pittsburgh, Pa., vice chairman. C. A. Erickson, The Peoples Natural Gas Company, Pittsburgh, Pa. is secretary.

Western Pennsylvania Corrosion Committee was organized in February 1954 as a sub-committee of the Corrosion Committee of the Pittsburgh Public Service Coordination Committee. The area of operation of the Western Pennsylvania Corrosion Committee was set as the western half of Pennsylvania. In July 1954 the committee became an independent organization with no sponsor but with the endorsement of the Pittsburgh Public Service Coordinating Committee.

From the outset the Western Pennsylvania Corrosion Committee was considered novel because its problems were well defined and the committee was tailor-made to cope with them. It was not an outgrowth or an adaptation of any other group with limitations and restrictions from another corrosion era. Neither was it the first committee of its kind in the area but has profited by other committee's experience. When the committee separated from the Pittsburgh Public Service Coordinating Committee, its area of operation was set at the north, west and south state lines of Pennsylvania and the Susquehanna River on the east. Anyone who operates a plant which influences structures within these boundaries may become a member. It was felt that any greater area of operation might become unwieldy and that anything less would be too limiting. Founders of the committee hope that in border cases aid can be had from neighboring groups such as those in Western New York or West Virginia.

The committee holds monthly meetings throughout the year. Any number of copies of the minutes of the committee's meetings will be sent to a member company. An example of how the committee handles problems is illustrated as follows: Company A wishes to protect a section of pipe line with a rectifier. It reports its intention to the committee and gives probable location. Progress is reported under new business in the minutes of the meeting of the committee. When the rectifier has been installed, it is assigned a case number which serves notification to all members to examine their plants for interference. When affected members are satisfied that the interference has been eliminated they so state in a meeting and it is duly recorded in the minutes. When 100 copies of this addition to the Rectifier Directory are received by the secretary, the case is closed. It may be reopened at any time for further study.

First major project undertaken by the Western Pennsylvania Corrosion Committee was a composite map showing all underground structures in Western Pennsylvania. The committee has prepared a coal mine mitigation directory and a rectifier and bond directory. These directories are kept current by reports at meetings of the committee. The committee feels that the rosters of the committee and the directories foster cooperation among the member companies.

The committee provides slides, mockups, demonstrations and data to anyone who is conducting a corrosion course.

When electrolysis groups are formed in the larger cities within the operating area, they are considered sub-committees of the larger group and their progress is reported in the minutes.

Pittsburgh Corrosion Committee Affiliates With NACE T-7A

Affiliation of the Corrosion Committee of the Pittsburgh Public Service Coordination Committee with the NACE T-7 organization was recently announced by C. A. Erickson, Jr., chairman of Group Committee T-7 and Unit Committee T-7A Northeast Region Corrosion Coordinating Committee.

Officers of the Corrosion Committee of the Pittsburgh Public Service Coordinating Committee, often called the Pittsburgh Corrosion Committee are C. M. Rutter, Equitable Gas Company, Pittsburgh, chairman; R. L. Smith, Duquesne Light Company, Pittsburgh, vice chairman; E. W. Steel, The Bell Telephone Company of Pennsylvania, secretary.

In February 1932 representatives from 16 companies and political sub-divisions began meeting to study jointly stray current problems in the areas served by the Pittsburgh Railway Company. The committee has been in continuous existence since then and at present has 27 members. Its area of operation is Allegheny County in Pennsylvania.

The committee holds monthly meetings, copies of the minutes of which are mailed to six states, Canada, Mexico, Europe, Brazil and South Africa. The Pittsburgh Corrosion Committee is considered to be the dean of the stray current committees and a fine example on which to pattern a city committee. Much credit for its success should be given to the Pittsburgh Public Service Corrosion Coordination Committee. E. W. Steel, secretary of the corrosion committee has been secretary since the committee's inception. The committee gives him much credit for its success.

ERRATA

On Page 94 of the April, 1957 issue of CORROSION, paragraph four of column three should read:

Set the price of the 1954-55 Bibliographic Survey of Corrosion at $12 for NACE members and $15 for non-members.

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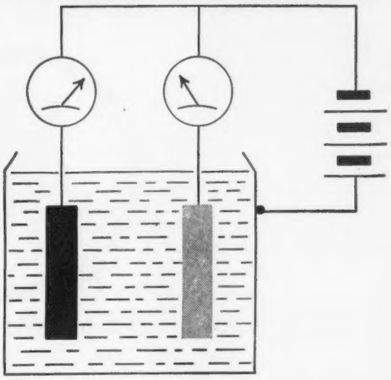

A test of relative current output in salt water was made using a NA Graphite Anode and a high silicon iron anode of identical dimensions connected in parallel and operated at a current density in the range of two to four amperes per square foot. Once readings had stabilized, the NA graphite anode carried 4.2 amperes, the high silicon iron anode only 2.0 amperes, with the same voltage applied to each. Interchanging the position of the test anodes had no effect on the readings. For a complete installation operated under these conditions, this indicates a power cost for graphite anodes of less than ½ that for high silicon iron anodes. This is over and above the savings obtained through the longer life and lower first cost of "National" NA Graphite.

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Erickson and Mercer Head NACE T-7 Unit

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Mercer

C. A. Erickson, Jr., The Peoples Natural Gas Company, Pittsburgh, Pa. has been appointed chairman of Technical Group Committee T-7 Corrosion Coordinating Committee when J. M. Fouts, Koppers Company, Inc., Pittsburgh, Pa., formerly with New York Telephone Company, Buffalo, New York, resigned. Mr. Fouts and Mr. Erickson as chairman and vice chairman were instrumental in formation and organization of the Corrosion Coordinating Committees.

C. L. Mercer, Southwestern Bell Telephone Company, Houston, Texas has been elected vice chairman to fill the vacancy. He was born in Oklahoma, received his college education at the University of Tulsa and at Rice Institute. He has been affiliated with the Southwestern Bell Telephone Company since 1933. In 1952 he was loaned to the Western Electric Company to work on the Distant Early Warning System in Alaska. Upon his return to Houston in 1953 he was transferred to the division staff to work on corrosion problems.

Mr. Mercer was one of the first members of the National Association of Corrosion Engineers, his membership application being dated May 1, 1944. He has been very active in the Technical Committee activities of the association for many years, has been member of Unit Committee T-4B on Corrosion of Cable Sheaths since the committee's origination and currently is vice-chairman of Task Group T-4B-5 on Non-Metallic Sheaths and Coatings and chairman of the Houston Corrosion Control Committee.

Wise and Segool—

(Continued from Page 89)

Committee T-2K on Prefabricated Plastic Film for Pipe Line Coating.

Frank E. Costanzo, Manufacturers Light and Heat Company, Pittsburgh, Pa. was chairman of the Unit Committee since its formation two years ago.

At the Unit Committee T-2K meeting in St. Louis the committee decided to reorganize its task groups. The committee originally had formed five task groups on history and results, physical characteristics, research and development, application and standards. The physical characteristics and standard task groups were combined into one to be called T-2K-1 on Standards. H. D. Segool is acting as chairman of this group. The research and development task group remains intact as T-2K-2 under a new chairman, H. A. Hendrickson.

Coburn, Rowe Head Inhibitor Committee

Coburn

Rowe

S. K. Coburn, Association of Amer can Railroads, Chicago, Illinois and I. C. Rowe, General Motors Corporatio , Detroit have been elected respectivel chairman and vice-chairman of NAC Technical Unit Committee T-3A o Corrosion Inhibitors. J. L. Wasco, Dov Chemical Company, Midland, Michigar is the outgoing chairman of the committee.

Mr. Coburn has served as vice-chairman of T-3A since the committee's meeting in March 1956. Mr. Coburn also is active in Unit Committee T-3E on Railroads and Task Group T-3E-1 on Corrosion of Railroad Tank Cars. He is editor of the T-3E Railroad Corrosion News Letter, a publication that is published twice a year for distribution to the management of railroad companies.

Los Angles Oil and Gas Unit Held Eight Meetings

Technical Unit Committee T-1A on Corrosion of Oil and Gas Well Equipment, Los Angeles Area held eight meetings during 1956. The committee acts as a corrosion forum for petroleum production engineers in the Southern California area. During 1956 efforts were made to program meetings in concert with those of the California Natural Gasoline Association Corrosion Committee. Interested members of each group were thereby given the opportunity to attend meetings of each group on alternate months, a plan proved to be of benefit to members of both committees.

T-1A continues to confine its interest to corrosion problems relating to oil and gas production practices but the members benefit from the experience of gasoline plant operators.

During 1956 programs were arranged to promote problem study among the member operators. Programs of the following type were prepared:

1. Chemical treatment of brines for injection into the ground.
2. Benefits of automatic lubrication of corrosion inhibitors in down-hole applications.
3. Cathodic protection of piers and well casings.
4. Advantages of the conductometric method of corrosion rate determinations.

Other programs included reviews of the NACE national conference and the sea-water corrosion conference held at La Jolla, California. Recent development in plastics technology and application, corrosion research and corrosion control applications were included.

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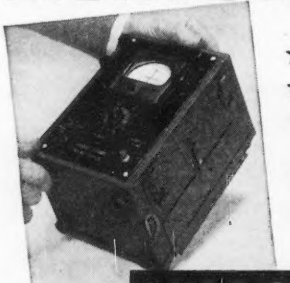

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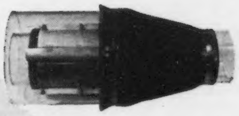

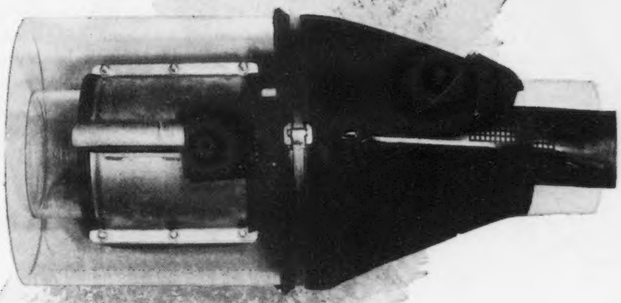

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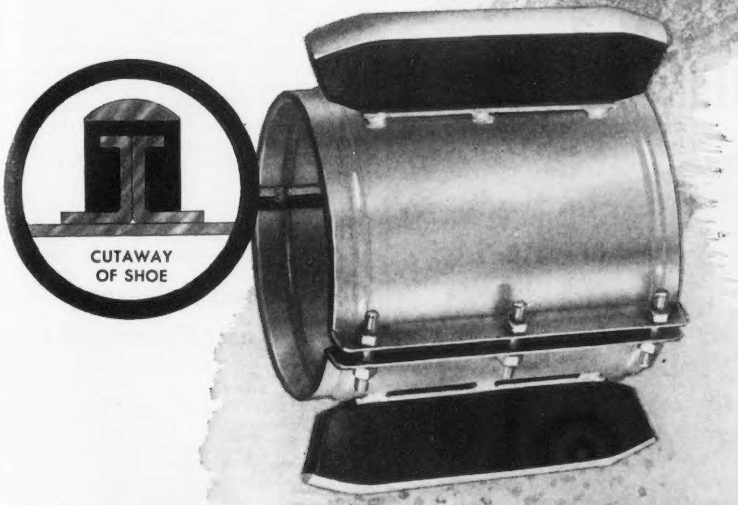

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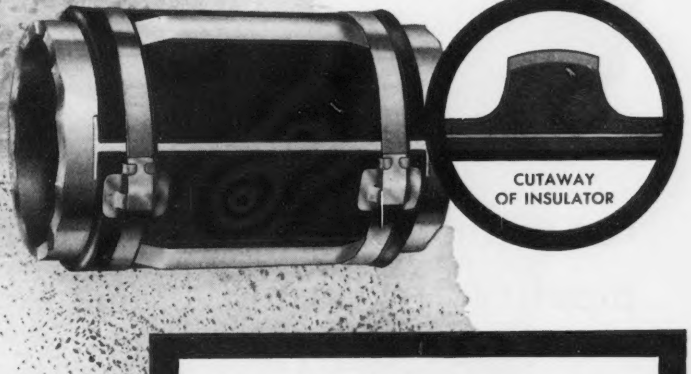
These insulators have superior insulation qualities because of the low moisture absorption and the long life compounded into the neoprene. The wide steel, sled type runners make installation easy. The extra wide band affords a positive grip. Bonded metal-to-neoprene-to-metal, the runner insulates and also permits flexibility to compensate for pipe shifting. Ribbed neoprene lining can be furnished if desired.



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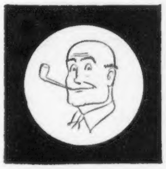

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Gleekman Is Chairman Of Chlorine Committee

L. W. Gleekman, Wyandotte Chemical Corp., Wyandotte, Mich. has been appointed chairman of NACE Task Group T-5A-4 on Corrosion by Chlorine. This appointment was announced recently by the chairman of Unit Committee T-5A, R. I. Zimmerer, Petro-Tex Chemical Company, Houston, Texas.

Wayne Inbody, Diamond Alkali Company, Painesville, Ohio was chairman of the task group for the past two years. Mr. Inbody submitted his resignation at the T-5A meeting held in St. Louis. The task group is planning a questionnaire designed to bring the committee up to date on corrosion of equipment used to handle cholrine.

T. L. Hoffman Heads HF Corrosion Task Group

T. L. Hoffman, Phillips Petroleum Company, Idaho Falls, Idaho has been reappointed chairman of Task Group T-5A-6 on HF Corrosion for a two year term. The task group announced at the Unit Committee T-5A meeting held in St. Louis that a report on HF Corrosion had been prepared by the committee and would be submitted to the unit committee in the near future. Plans have been tentatively made to present the report as a paper at a NACE Regional meeting or the next annual conference.

Products Pipe Line Coupon Tests Are Surveyed by T-2E

Parker

Three sets of corrosion coupons, two from product pipe lines using oil soluble inhibitors and one from product pipe line using inorganic inhibitors were examined and discussed at the T-2E Internal Corrosion of Product Pipe Lines and Tanks meeting held at St. Louis. The corrosion coupons were some of those that had been placed in pipe lines in connection with the T-2E in-line corrosion coupon test initiated in 1956. Dr. Ivy M. Parker, Plantation Pipe Line Company, Atlanta, Ga. chairman of T-2E reported that good results were obtained in each of the cases discussed at the meeting.

Data furnished to the committee indicated that many product storage tanks suffer severe corrosion. Coatings and inhibitors were discussed as a remedial measure. A questionnaire will be prepared and a survey will be made to ascertain the extent of tank corrosion problems.

Unit Committee T-2E planned to hold its next meeting in conjunction with the Northeast Region NACE meeting in Pittsburgh, November 12-14, 1957.

Accelerated Galvanic Anode Tests Considered

Development of standard accelerated galvanic anode test procedures has been assigned to Task Group T-2A-2 under Unit Committee T-2A on Galvanic Anodes for Cathodic Protection. H. A. Robertson, Dow Chemical Company, Midland, Michigan was appointed chairman.

Other members are T. J. Lennox, Jr., American Smelting and Refining Company, South Plainsfield, New Jersey; R. L. Horst, Jr., Aluminum Company of America, New Kensington, Pa. and F. E. Costanzo, Manufacturers Light and Heat Company, Pittsburgh, Pa.

The task group assignment was made at a T-2A meeting at the NACE Annual Conference in St. Louis attended by seventy-five members and guests.

It was decided also to terminate Task Group T-2A-1 on Ribbon Anodes. The committee decided to review work of the task group and consider preparation of an interim report.

Attendance Nearly 10,000 At St. Louis Sessions

Attendance at technical sessions exclusive of committee meetings held during the 13th Annual Conference at St. Louis in March has been estimated at 9364. The attendance ranged from a minimum of 48 to a maximum of 350. Average attendance was 137.

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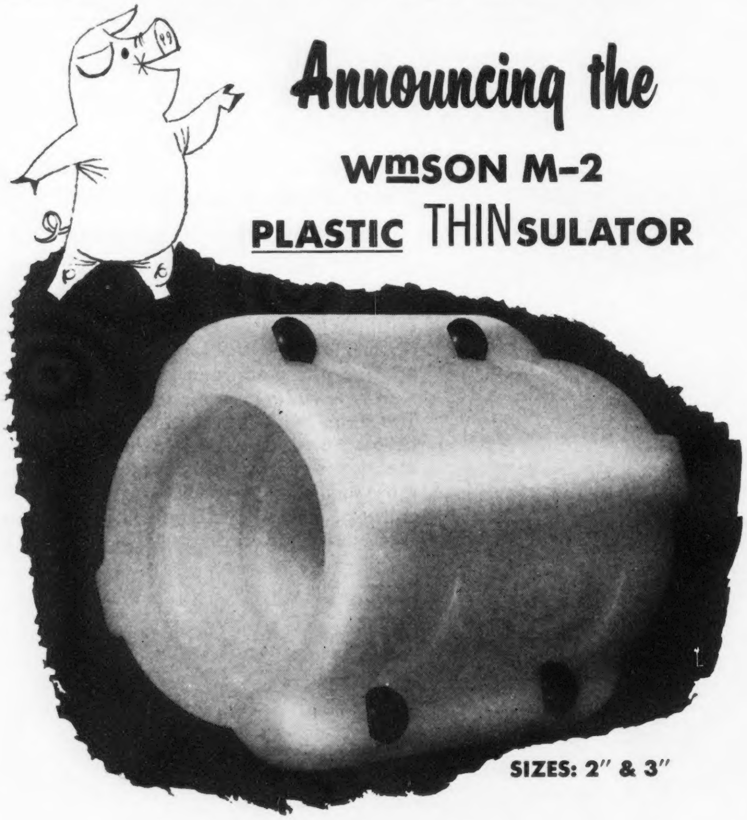

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Sulfide Stress Corrosion Cracking Unit Terminates As Research Report Is Approved

With approval of the report on sponsored research at Yale University on Hydrogen Sulfide Stress Corrosion Cracking entitled "Hydrogen Absorption, Embrittlement and Fracture of Steel," Unit Committee T-1G on Sulfide Stress Corrosion Cracking considers its initial objective has been completed satisfactorily. The committee voted to terminate as a unit committee at a meeting held in St. Louis. It will continue to function as a task group under Unit Committee T-1F on Metallurgy. The committee's task group designation will be T-1F-1 on Sulfide Stress Corrosion Cracking.

Spontaneous failure of steel in media containing hydrogen sulfide assumed serious proportions in the petroleum industry in 1950 as a result of failure of alloy tubing in some sour gas condensate wells. The serious character of the problem was not defined by the number of failures but by the magnitude of the economic and technical hazard implied by the failures. Early recognition of the problem led to extensive laboratory and field investigations by the operating companies and within the NACE Technical Practices Committee TP-1G, later known as Unit Committee T-1G

A summary of laboratory and field investigations was published by NACE in 1952.

It was anticipated that effective field measures could be taken only when and if a reasonably complete mechanism was available. Further, the specifications and interpretations of laboratory testing procedures also depended on a detailed knowledge of the mechanism. Accordingly, in 1951 the NACE Technical Practices Committee TP-1G initiated research in the Metallurgy Department at Yale University for the purpose of investigating the mechanism of failure of steel in hydrogen sulfide. The report "Hydrogen Absorption, Embrittlement and Fracture of Steel" contains the summary of experimental data and conclusions drawn from the work conducted at Yale University from 1951 to September 1955. The report has been reviewed by members of Unit Committee T-1G and approved. It has been submitted to the Technical Practices Committee chairman who has recommended the report be published. It is anticipated the report will be published soon in CORROSION. Reprint copies of the report will be made available from NACE Central Office.

T-8 on Refining Industry Corrosion Is Approved

The Technical Practices Committee and the NACE Board of Directors have approved formation of NACE Technical Group Committee T-8 on Refining Industry Corrosion. M. E. Holmberg, consulting engineers, Houston has been appointed chairman. E. B. Backensto of the Socony Mobil Oil Company in Paulsboro, New Jersey is the vice chairman and Cecil Phillips, Humble Oil & Refining Company, Baytown, Texas is secretary.

Group Committee T-8 held its organization meeting during the recent NACE Conference in St. Louis. Formation was an outgrowth of Task Group T-5B-2 on Sulfide Corrosion at High Temperatures and Pressures in the Petroleum Industry, organized in 1954 and dissolved after its assignment had been essentially completed in San Antonio in October, 1956.

Success of the task group assignment led members to believe that further work on other corrosion problems in the petroleum refining industry should be done by the committee. Plans are being made for studies on other aspects of corrosion in the petroleum refining industry. Most members of Task Group T-5B-2 are now members of Group Committee T-8.

The chairman of Group Committee T-8 invites all NACE members interested in working on corrosion in the petroleum refining industry to contact him at 4101 San Jacinto Street, Houston. Second meeting of Group Committee T-8 will be held in October of this year at a location to be announced later.

Pump Parts Inquiry Task Group Probe Is Started

A task group has been appointed by Unit Committee T-1D on Sour Oil Well Corrosion to investigate brand names and metal compositions of pumps to see whether a chart by brand names of metallurgically similar parts should be compiled. The task group will also attempt to ascertain whether the producing companies have sufficient records to indicate what pump parts show the greatest percentages of failure. It may prepare methods whereby the difference between failures caused by corrosion and those attributable to other causes can be distinguished. F. A. Prange, Phillips Petroleum Company, Bartlesville, Oklahoma was appointed chairman of the group.

H. M. Cooley Is Elected by Metallurgy Committee

H. M. Cooley, Bethlehem Steel Company, Tulsa, Oklahoma became chairman of NACE Unit Committee T-1F on Metallurgy at the committee's meeting at St. Louis during the annual conference. Monte Kaplan, Atlantic Refining Company, Dallas, chairman of T-1F since March 1956, resigned because of re-assignment of duties in his company. Mr. Kaplan also was chairman of Unit Committee T-1G Sulfide Stress Corrosion Cracking, now a task group under Unit Committee T-1F on Metallurgy.

J. J. B. Rutherford, Tubular Products Division, Babcock and Wilcox Company, Beaver Falls, Pa. will be chairman of Task Group T-1F-1 on Sulfide Stress Corrosion Cracking.

Salt Spray Test Discussed

At the April 25-26 meeting of the Institute of Environmental Engineers at Chicago, the following paper was presented:

A Critical Analysis of the Salt Spray Test, Carl Durbin, Chrysler Engineering Division, and Walter Cavanaugh, Parker Rust Proof Company.

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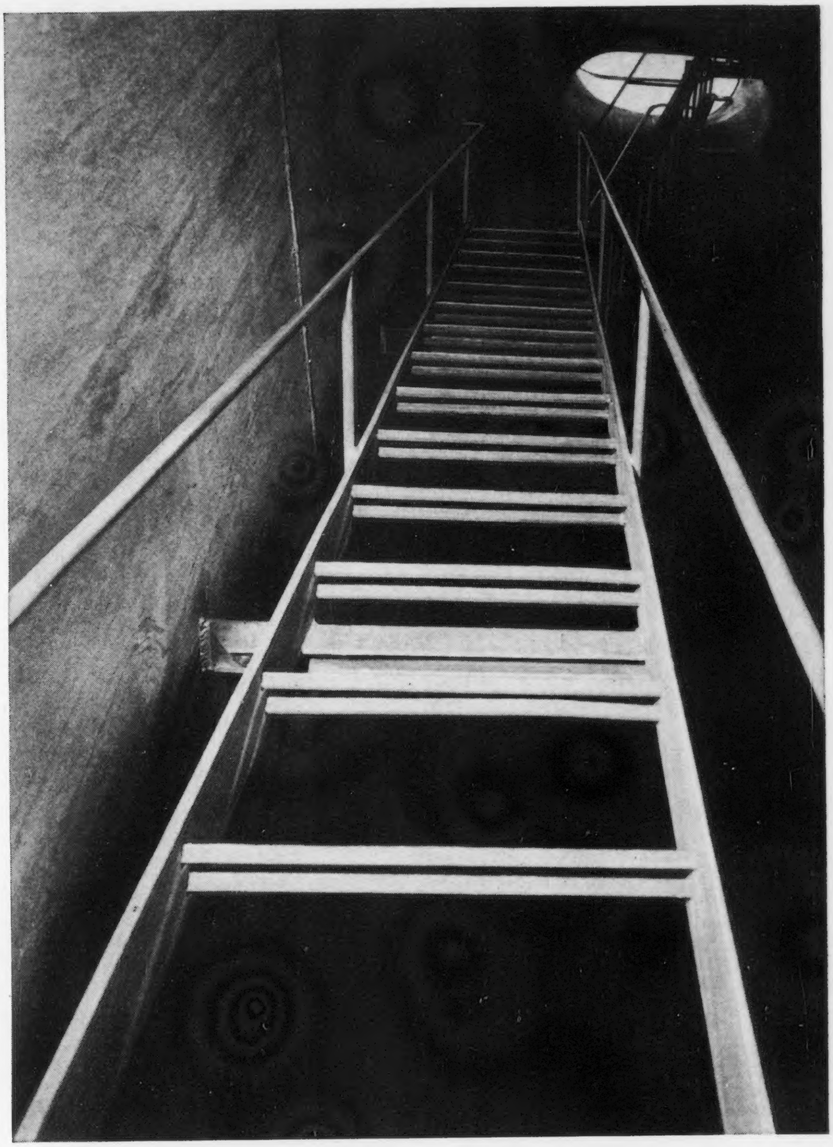

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T. J. Maitland Reelected to Second 2-Year Term by T-2B

T. J. Maitland, American Telephone and Telegraph Company, New York, New York has been re-elected to a second two-year term as chairman of Unit Committee T-2B on Anodes for Impressed Current. J. S. Dorsey, Southern California Gas Company, Los Angeles, California has been elected vice-chairman of T-2B and L. A. Hugo, Phillips Petroleum Company, Bartlesville, Oklahoma has been elected secretary.

At the T-2B meeting held at St. Louis a second report on use of high silicon cast iron for anodes was made by Task Group T-2B-4. The first report on high silicon cast iron anodes was published in the February 1957 issue of Corrosion. It is anticipated that the second report will be reviewed by the unit committee and possibly submitted for publication some time during 1957.

Structural Plastics Unit To Elect New Officers

B. W. Bradley, Shell Oil Company, Berkeley, California chairman of T-1J since the committee's meeting in March 1956 has resigned as chairman of NACE Unit Committee T-1J on Oil Field Structural Plastics. Mr. Bradley's company work assignment has changed to preclude his further activity on the committee.

W. B. Sanford, Minnesota Mining and Manufacturing Company, St. Paul, Minnesota was the vice-chairman of T-1J. Mr. Sanford also resigned because of a transfer within his company. New officers will be selected by the committee by letter ballot after a report is made of the selection of nominees by a nominating committee appointed at St. Louis.

Protective Coatings Unit Headed by Van Delinder

Van Delinder

L. S. Van Delinder, Carbide and Carbon Chemical Corp., South Charleston, West Virginia has been appointed chairman of Technical Unit Committee T-6 on Protective Coatings by C. P. Larrabee, chairman of the Technical Practices Committee at the meeting in St. Louis.

Mr. Van Delinder's appointment was for a one-year term to expire at the end of NACE Conference in March 1958. Mr. Van Delinder was elected vice-chairman of Unit Committee T-6 and had served in that capacity since March 1956.

The appointment was made necessary by the resignation of the T-6 chairman L. L. Whiteneck, Plicoflex, Inc., Los Angeles who was elected vice-president of NACE for 1957-58. Duties of that office were responsible for his resignation.

Bigos to Investigate Need For Further T-6G Work

Bigos

Joseph Bigos, United States Steel Corporation, Applied Research Laboratory, Monroeville, Pa. has been appointed temporary chairman of NACE Technical Unit Committee T-6G on Surface Preparation for Organic Coatings. The appointment of a temporary chairman became necessary when both the chairman and vice chairman of the committee submitted resignations. Dr. Bigos was asked to ascertain in what fields of study the committee should continue to work or if the committee shows no interest in further work to initiate proceedings for termination.

Complete Five-Year Set of Corrosion Issues Offered

A complete file of Corrosion for five years, including current issues is available from Logan W. Glass, formerly with B. F. Goodrich Co. Any person or firm interested in securing this complete file is invited to write to Mr. Glass, in case of Corrosion, 1061 M & M Bldg., Houston 2, Texas.

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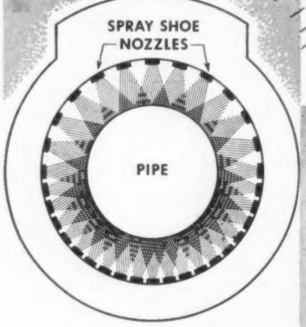

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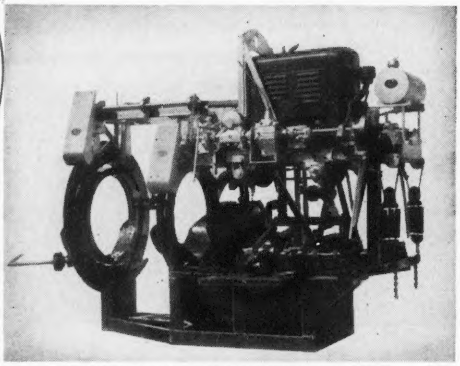
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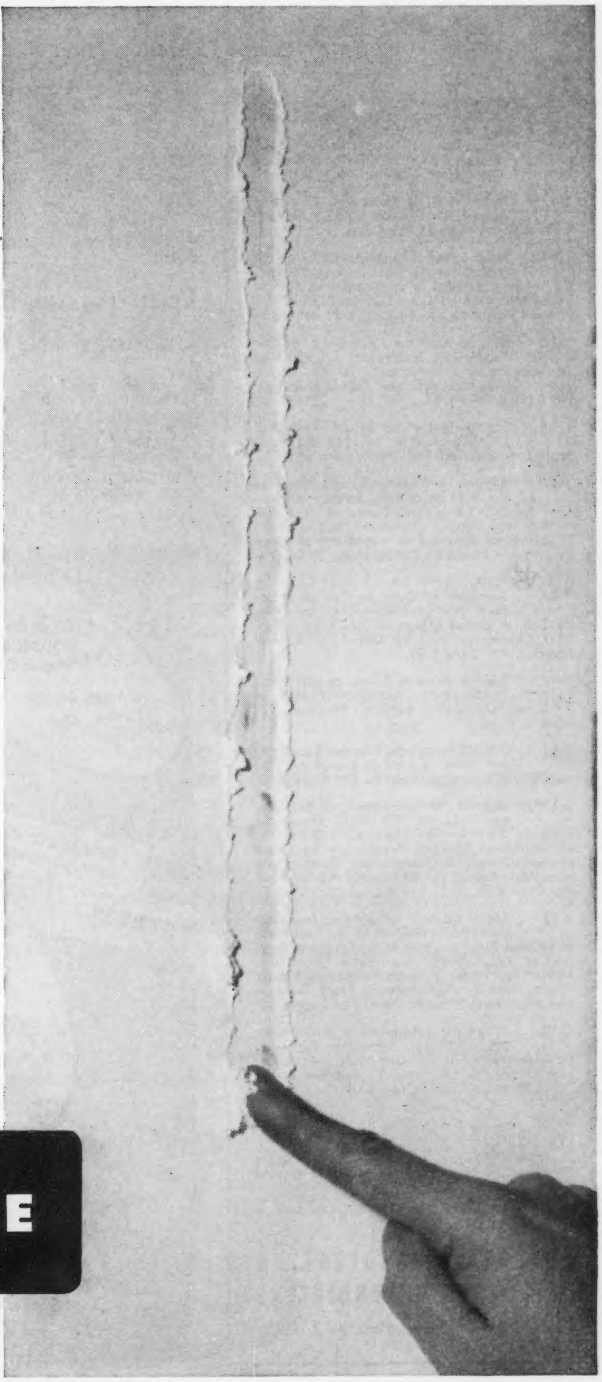

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T-1A Survey of Corrosion Control in California Pumping Wells. A Report of T-1A on Corrosion in Oil and Gas Well Equipment, Los Angeles Area. Pub. 54-7. Per Copy, $.50.

T-1C Current Status of Corrosion Mitigation Knowledge on Sweet Oil Wells. A Report of Technical Unit Committee T-1C on Sweet Oil Well Corrosion. Per Copy, $.50.

T-1C Field Practices for Controling Water Dependent Sweet Oil Well Corrosion. A Report of Technical Unit Committee T-1C on Sweet Oil Well Corrosion, Compiled by Task Group T-1C-1 on Field Practices. Pub. No. 56-3, Per Copy $1.00.

TP-1D Sour Oil Well Corrosion. *Corrosion* August, 1952, issue. NACE members, $.50; Non-members $1 Per Copy.

TP-1G Field Experience With Cracking of High Strength Steel in Sour Gas and Oil Wells. (Included in Symposium on Sulfide Stress Corrosion.) (Pub. 52-3) $1 Per Copy, 5 or more copies to one address, $.50 Per Copy.

T-1G Sulfide Corrosion Cracking of Oil Production Equipment. A Report of Technical Unit Committee T-1G on Sulfide Stress Corrosion Cracking. Pub. 54-5. $.50 Per Copy.

T-1J Status Report of NACE Technical Unit Committee T-1J on Oil Field Structural Plastics. Per Copy $1.00.

T-1J Reports to Technical Unit Committee T-1J on Oilfield Structural Plastics. Part 1, Long-Term Creep of Pipe Extruded from Tenite Butyrate Plastics. Part 2, Structural Behavior of Unplasticized Geon Polyvinyl Chloride. Publication 55-7. Per Copy $.50.

T-1J Summary of Data on Use of Structural Plastic Products in Oil Production. A Status Report of NACE Technical Unit Committee T-1J on Oilfield Structural Plastics. Per Copy $.50.

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T-1K Proposed Standardized Laboratory Procedure for Screening Corrosion Inhibitors for Oil and Gas Wells. A Report of T-1K on Inhibitors for Oil and Gas Wells. Publication 55-2. Per Copy $.50.

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Marine Deterioration Group Elects Wakeman

Wakeman

Acting on a recommendation by the Technical Practices Committee the NACE Board of Directors has approved formation of a new Group Committee T-9 on Marine Biological Deterioration. This group was formerly known as the Marine Biological Deterioration Conference of the Sea Horse Institute. Members of the conference voted by letter ballot to become affiliated with NACE and to become a technical committee of the Association. C. M. Wakeman, Consultant, Los Angeles, California was appointed chairman of the Group Committee T-9. Election of other officers and committee objectives will be announced in the near future.

Low Pressure Gasoline Plant Coatings Are Discussed

Interim reports on recommendations for coatings used in low pressure gasoline plants and coatings and methods for tanks were presented to Unit Committee T-6E on Protective Coatings in Petroleum Production at the committee's meeting in St. Louis. M. J. Olive, Arkansas Fuel Oil Corporation, Shreveport, Louisiana presented the report on low pressure gasoline plants and C. J. Fritts, Socony Paint Products Co., Houston, presented the report on tanks.

Also presented at the T-6E meeting were results of a committee questionnaire submitted to determine present practices and field data that might supplement contemplated recommended practices and suggested specifications for protective coatings used in petroleum production. Results were tabulated and the statistical study was offered to the chairman of the various task groups for use in developing final recommendations.

Chemical Coatings Unit Names C. G. Munger

C. G. Munger, Amercoat Corporation, South Gate, California became chairman of NACE Technical Unit Committee T-6A on Organic Coatings and Linings for Resistance to Chemical Corrosion when R. McFarland, Jr., Hills-McCanna Co. of Chicago, Illinois resigned the chairmanship at the St. Louis meeting. Mr. McFarland was appointed co-chairman of the technical program committee for the NACE Conference to be held in San Francisco in March 1958. He felt he could be active in Unit Committee T-6A and satisfactorily carry out the assignment on technical program. Mr. Munger said a nominating committee has been appointed to select nominees to be voted on to fill the vacancy in office of vice chairman.

•

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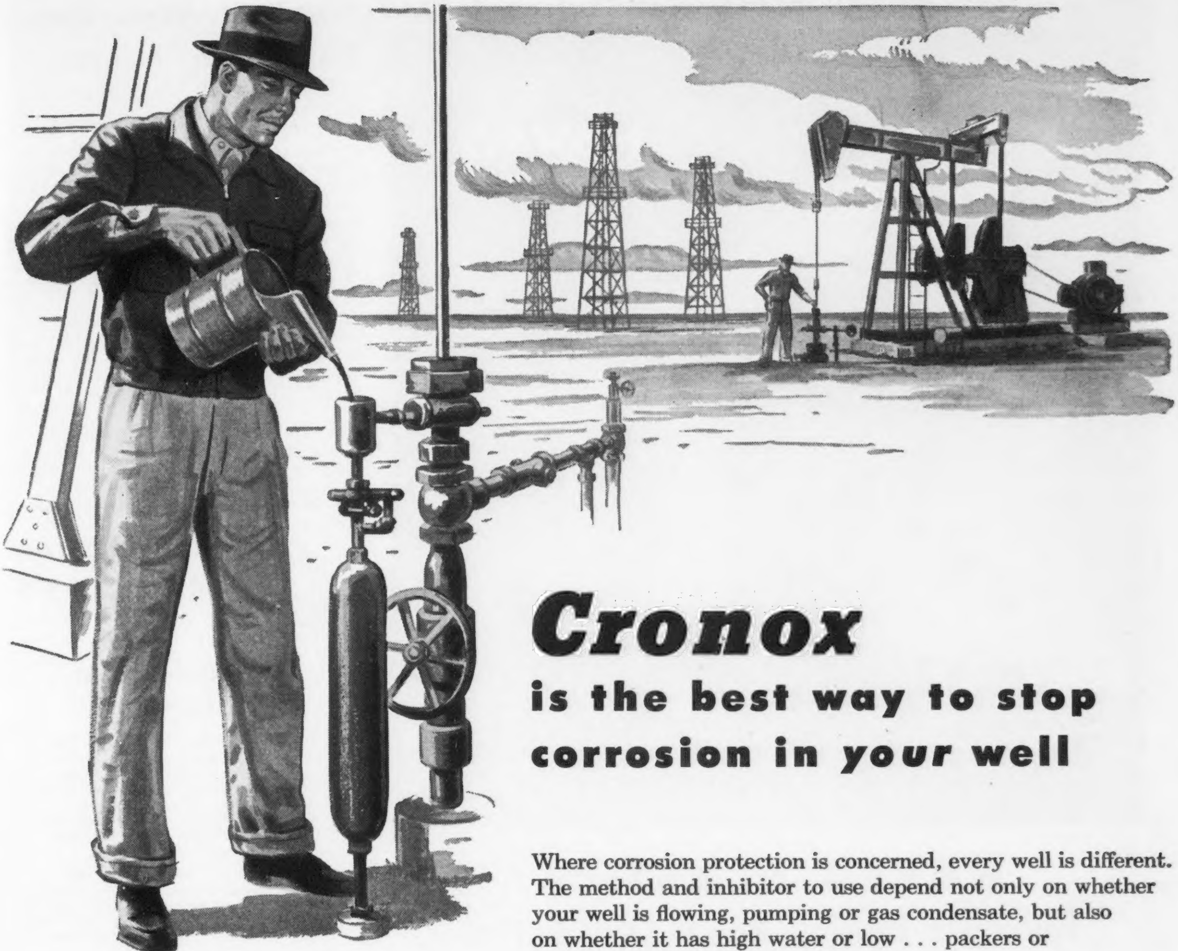

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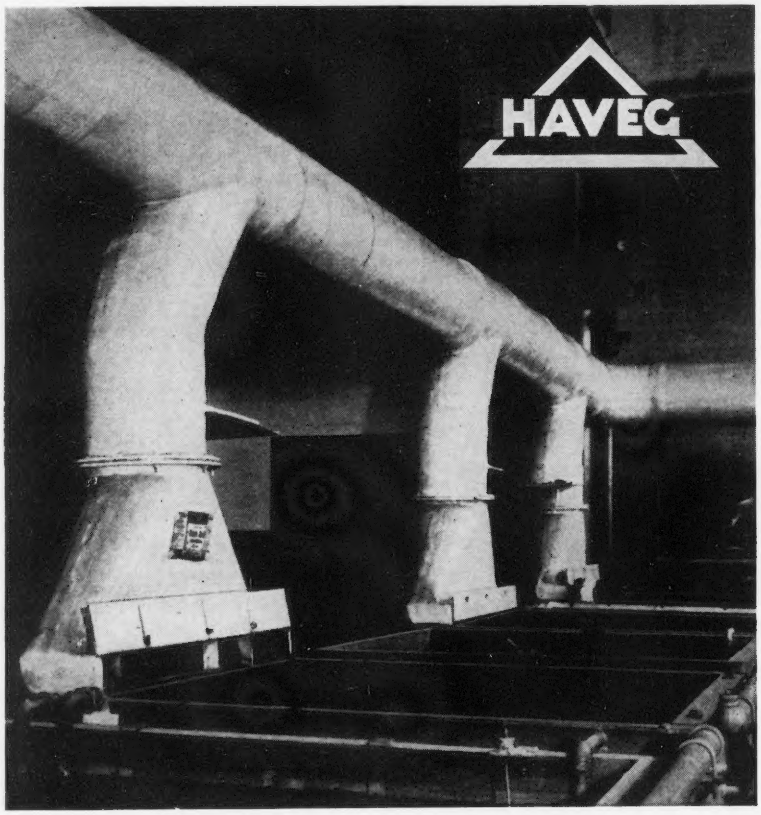

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High Purity Water Unit Elects Blaser Chairman

R. U. Blaser, Babcock and Wilcox Company, Alliance, Ohio has been elected chairman of Technical Unit Committee T-3F on Corrosion in High Purity Water. J. F. Eckel, Department of Metallurgical Engineering, Virginia Polytechnic Institute, Blackburg, Virginia has been re-elected to a second two-year term as vice chairman of T-3F. Mr. Blaser served as chairman of the High Purity Water Symposia held at the 12th annual NACE Conference in New York in 1956 and at St. Louis at the recent NACE Conference. A symposium on high purity water is being planned by the committee for the NACE Conference to be held at San Francisco in March 1958.

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The 10-Year Index, published in 1956, contains more than 4000 reference phrases to material in issue published 1945-54 inclusive.

TECHNICAL REPORTS
on
CORROSION in UTILITIES

T-4B Cell Corrosion on Lead Cable Sheaths. Third Interim Report of Technical Unit Committee T-4B on Corrosion of Cable Sheaths. Compiled by Task Group T-4B-1 on Corrosion of Lead and Other Metallic Sheaths. Publication No. 56-9. Per Copy $.50.

T-4B-2 Cathodic Protection of Cable Sheaths. Fourth Interim Report of Technical Unit Committee T-4B on Corrosion of Cable Sheaths. Compiled by Task Group T-4B-2 on Cathodic Protection. Publication 56-13. Per Copy $1.00.

T-4B-3 Tests and Surveys for Lead Sheathed Cables in the Utilities Industry. Second Interim Report of Technical Unit Committee T-4B on Corrosion of Cable Sheaths. Publication 54-6. Per Copy $.50.

T-4B-4 Pipe-Type Cable Corrosion Protection Practices in the Utilities Industry. First Interim Report of Technical Unit Committee T-4B on Corrosion of Cable Sheaths. Publication 54-3. Per Copy $.50.

T-4B-6 Stray Current Electrolysis. Fifth Interim Report of Technical Unit Committee T-4B on Corrosion of Cable Sheaths, prepared by Task Group T-4B-6 on Stray Current Electrolysis. Publication No. 57-1. Per Copy $1.00.

T-4F-1 Progress Report of Task Group T-4F-1 on Water Meter Corrosion. Per Copy $.50.

TP-12 Report on Electrical Grounding Practices. Per Copy $.50.

TP-19 Corrosive Effects of Deicing Salts—A Progress Report by Technical Practices Committee 19. *Corrosion*, January, 1954, issue. NACE members $.50; Non-members $1 per copy.

Remittances must accompany all orders for literature the aggregate cost of which is less than $5. Orders of value greater than $5 will be invoiced if requested. Send orders to National Association of Corrosion Engineers, 1061 M & M Bldg., Houston, Texas. Add 65c per package to the prices given above for Book Post Registry to all addresses outside the United States, Canada and Mexico.

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NACE NEWS

Three-Day Syracuse Meeting Opens May 20

Technical Papers, Other Events Set By Northeast Region

The three-day program of Northeast Region at Syracuse University May 20-22 includes eleven technical papers, a round table discussion, laboratory demonstrations and two plant tours. A complete program will be found in April CORROSION, Page 81.

Papers include discussions of inhibitors, coatings, high purity water, power plants, chemical industry materials, lead cable sheaths, cathodic protection, plastics and valves. Theme of the meeting is "Corrosion Control by Choice of Materials."

Registration opens at 9 am, Monday, May 20, in the foyer of Maxwell Hall, University of Syracuse, N. Y.

Teche Section Short Course Topics Listed

Topics for the June 6-7 Short Course on Corrosion to be held at the Southwestern Louisiana Institute, Lafayette, La. by Teche Section NACE have been given as follows by M. I. Suchanek, Dowell, Inc., Lafayette:

Thursday, June 6

Morning: Registration, introduction, Fundamentals of Corrosion. Laboratory and Field Methods of Determining Corrosion. Corrosion Control of Oil and Gas Wells. Plastic Materials for Corrosion Control.

Afternoon: Role of Alloys in Corrosion Prevention. Corrosion Protection of Marine Lines and Structures. Demonstrations.

Friday, June 7

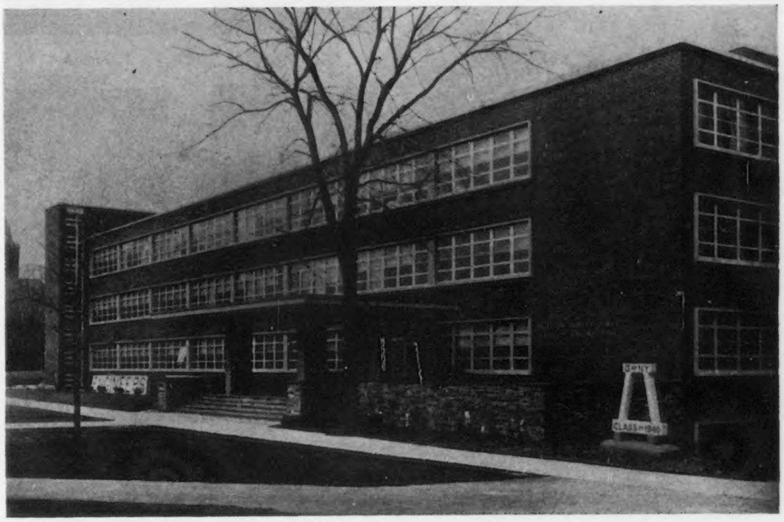
Morning: Selling Corrosion Control to Management. Cathodic Protection of Underground Pipelines. Theory of Chemical Inhibitors. Field Application of Chemical Inhibitors.

Afternoon: Protecting Oil Well Casing from Corrosion. University of Texas Extension Service film on Corrosion. Round table discussion.

Registration fee of $15 includes two noon meals, Fellowship Hour and Thursday night banquet at Lafayette Petroleum Club.

Dorsey Is New Chairman Of Los Angles Section

The following newly elected 1957 officers of Los Angeles Section were installed at the March 27 meeting of the section: J. S. Dorsey, Southern California Gas Company, chairman; C. E. Hedborg, Union Oil Company of California, vice-chairman; and J. Glen Lacy, Amercoat Corporation, secretary-treasurer.



NORTHEAST REGION'S May 20-22 meeting will be held in Hinds Hall of Engineering, Syracuse University, Syracuse, N. Y. Lectures will be on the campus and demonstrations in this building.

SPEAKERS AT A JOINT NACE-AES-ECS meeting March 26 at University of Maryland are, left to right: B. J. Philibert, Weather Mastic Co.; J. Kruger, National Bureau of Standards; E. C. Bertucio, Western Electric Co.; G. F. Corcoran, dean, Department of Electrical Engineering, University of Maryland; Ralph Roberts, Office of Naval Research; W. J. Hamer, NBS; W. J. Mayer, A. M. Byers Co. and Mrs. J. Burbank, NBS.

Baltimore Section Participates in Second Annual Joint Electrochemistry Meeting

Eight members and guests attended a joint meeting of three Baltimore-Washington area engineering organizations, The Second Annual Joint Meeting on Electrochemistry, March 26 at University of Maryland. Represented were members of the American Elecrtoplaters Society, Electrochemical Society and the National Association of Corrosion Engineers.

Ralph Roberts, Office of Naval Research made the prinicpal address concerning his recent experiences during a tour of Europe as scientific liaison officer of the American embassy in London. He discussed aspects of electrochemical research in Europe including electroplating, corrosion and research methods, including work at Cebelcor and other laboratories. Slides in color illustrated his talk.

Other items on the program were:

Why a Joint Meeting? by J. Kruger, National Bureau of Standards.

NACE's Approach to Corrosion Mitigation, B. J. Philibert, Weather Mastic Co. and W. J. Mayer, A. M. Byers Co.

Relationship of the American Electroplaters Society to the Electrochemical Society, E. C. Bertucio, Western Electric Co. and Jules Horelick.

Electrochemical Society and Advances in Theoretical Electrochemistry, W. J. Hamer and Mrs. J. Burbank, NBS.

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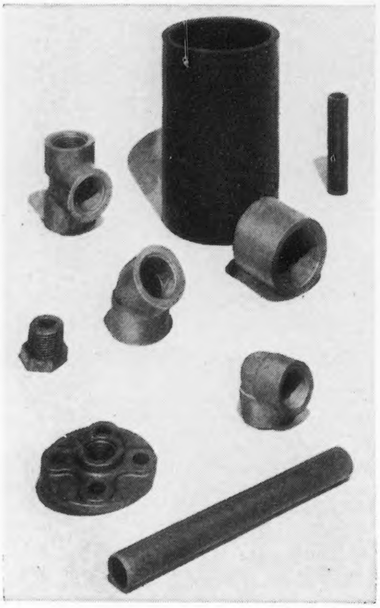

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Officials for North Central October Meeting Are Named

Officials and committee chairmen for the 1957 North Central Regional Meeting to be held in Chicago October 1-4 at Sherman Hotel, Chicago, have been named as follows:

General Arrangements—R. B. Janota, Swift & Co.; P. E. Henneberry, Amercoat Corp.

Technical Program—E. F. Moorman, International Harvester Co.; L. V. Collings, Sinclair Research Corp.

Local Arrangements—P. E. Henneberry; Ralph Bowers, Capitol Chemical.

Entertainment—L. O. Risetter, Industrial Coatings Corp.; Larry Bott, National Aluminate Corp.

Registration and Printing—J. J. Irwin, Revere Chemical Co.; R. J. Kowal.

Publicity—D. G. Keefe, Swift & Co.; John Anthony, Johns-Manville Co.

Finance—C. B. Smith, W. H. Schultz, Dearborn Chemical Co.

Ladies: Mdms. R. B. Janota and L. O. Risetter.

Spokane Short Course Program Is Given

Following is the schedule for the April 8-11 Corrosion Short Course held at the Davenport Hotel, Spokane, Wash. The course was sponsored by the Technical Extension Service of Washington State Institute of Technology, State College of Washington in cooperation with NACE.

Monday, April 8

Physiochemical Factors, M. J. Pryor, Kaiser Aluminum and Chemical Corp., Spokane.

Metallurgical and Mechanical Factors, J. M. Beeston, State College of Washington.

Tuesday, April 9

Design of Equipment from the Corrosion Standpoint, Bruce H. Levelton, British Columbia Research Council, University of British Columbia, Vancouver.

Selection of Materials of Construction, Bruce H. Levelton.

Diagnosis of Corrosion Problems, speaker not listed.

Evaluation of Corrosion Data, speaker not listed.

Wednesday, April 10

Coatings: Theory and Practical Application, George Martin, Parker Paint Mfg. Co., Tacoma, Wash.

Coatings: Special Coatings and Techniques, J. A. Ayres, Hanford Laboratory, General Electric Co., Richland, Wash.

Laboratory and Plant Testing for Corrosion, J. A. Ayres.

Outlook for Nuclear Industry, D. W. McLenegan, General Electric Co., Richland. (Banquet address)

Thursday, April 11

Fundamentals of Cathodic Protection, Mark W. Battersby, Farwest Corrosion Co., Inc., Seattle, Wash.

Theory and Use of Corrosion Testing Equipment, Bethel Bond, Farwest Corrosion Co., Inc.

Jacksonville Section Has One-Day Technical Meeting

A one-day technical program and buffet supper was scheduled April 26 by Jacksonville Section at Roosevelt Hotel, Jacksonville.

The program included: Modern Usage of Plastic Pipe and Tubing, G. W. Fine, Southern Industrial Supply Corp., St. Petersburg, Fla.

Corrosion Problems and Present Answers in the Public Utilities Industry, J. B. Prime, Jr., Florida Power & Light Co., Miami.

Corrosion Problems and Present Answers in the Phosphate Chemicals Industry, O. C. Chapman, Wyllys Taylor, Virginia-Carolina Chemical Co.

Corrosion Problems and Present Answers in the Southeastern Pulp and Paper Industry, D. F. Roberts, St. Regis Paper Co., Eastport, Fla.

Corrosion Problems and Present Answers in the Transport Industry, by a Dow Chemical Co. engineer.

Use of Inhibitors to Check Metallic Corrosion, by a National Aluminate Corp. engineer.

A panel discussion was held beginning at 4 pm, moderated by E. P. Tait, Alloy Steel Products Co., Atlanta.

A dinner address was scheduled by J. Hall Carpenter, Carpco Manufacturing Co., Jacksonville.

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Symposia Chairmen Are Named for Oct. 1-4 Meeting of South Central Region

Chairmen have been named for the five symposia to be given at the October 1-4 Oklahoma City meeting of NACE's South Central Region as follows:

Thursday, Oct. 3

Corrosion in the Gas Distribution Industry. O. W. Everett, Oklahoma Natural Gas Co., Tulsa and Robert Nee, Robert Nee Co., Tulsa, co-chairmen.

Marine Corrosion. R. M. Robinson, Continental Oil Co., New Orleans and Otto L. Gross, California Co., Harvey, La., co-chairmen.

Process Industry—Session 1. W. G. Ashbaugh, Carbide & Carbon Chemicals Co., Texas City; C. P. Dillon, Carbide and Carbon Chemicals Co., Texas City, co-chairmen.

Thursday, October 3

Cathodic Protection. Y. W. Titterington, Corrosion Services, Inc., Tulsa; James F. Stephenson, Gulf Refining Co., Houston, co-chairmen.

Process Industry Symposium—Session 2. Same as Session 1.

Friday, October 4

Corrosion in Oil and Gas Production. J. L. Battle, Humble Oil & Ref. Co., Houston; W. C. Koger, Cities Service Oil Co., Bartlesville, Okla., co-chairmen.

Protective Coatings. L. G. Sharpe, Napko Corp., Odessa, Texas.

Design Factors Discussed At North Texas Meeting

Frank L. Whitney, Jr., Monsanto Chemical Company, St. Louis, spoke on Design for Corrosion at the March 4 meeting of North Texas Section.

Mr. Whitney discussed comprehensively factors to minimize corrosion to be considered at the design stage. He said first consideration should be to select a location which has minimum inherent corrosion and the second requirement is ease of maintenance of structures.

He then explained that four major pitfalls must be avoided in designing process equipment: galvanic corrosion, crevice corrosion, stress corrosion and unnecessarily corrosive process conditions. Mr. Whitney concluded his remarks with a description of several practical measures for minimizing tank corrosion.

There were 29 members and guests present.

Inhibitor Evaluation Is East Texas Section Topic

Methods of evaluating the merits of inhibitors in the laboratory were discussed by E. J. Simmons, Sun Oil Co. at a meeting of East Texas Section March 26. The Longview meeting was attended by 15 members and 26 guests.

During the discussion following Mr. Simmons talk it was brought out that cathodic protection may be improved by film type inhibitors and hindered by other kinds, such as the chromates.

No section meetings are scheduled during June, July and August. Nominations for a new chairman were scheduled at the April meeting.

Schaschl Joins Committee

Edward Schaschl, Pure Oil Co., Crystal Lake, Ill. is a new member of the NACE Abstract Sub-Committee. Mr. Schaschl takes the place vacated by Miss Rosemary Smith, resigned because she is leaving the International Nickel Co.

Mr. Schaschl, who has co-authored papers published in CORROSION on inhibitors and inhibitor testing, is in charge of his company's abstract punch card reference service.

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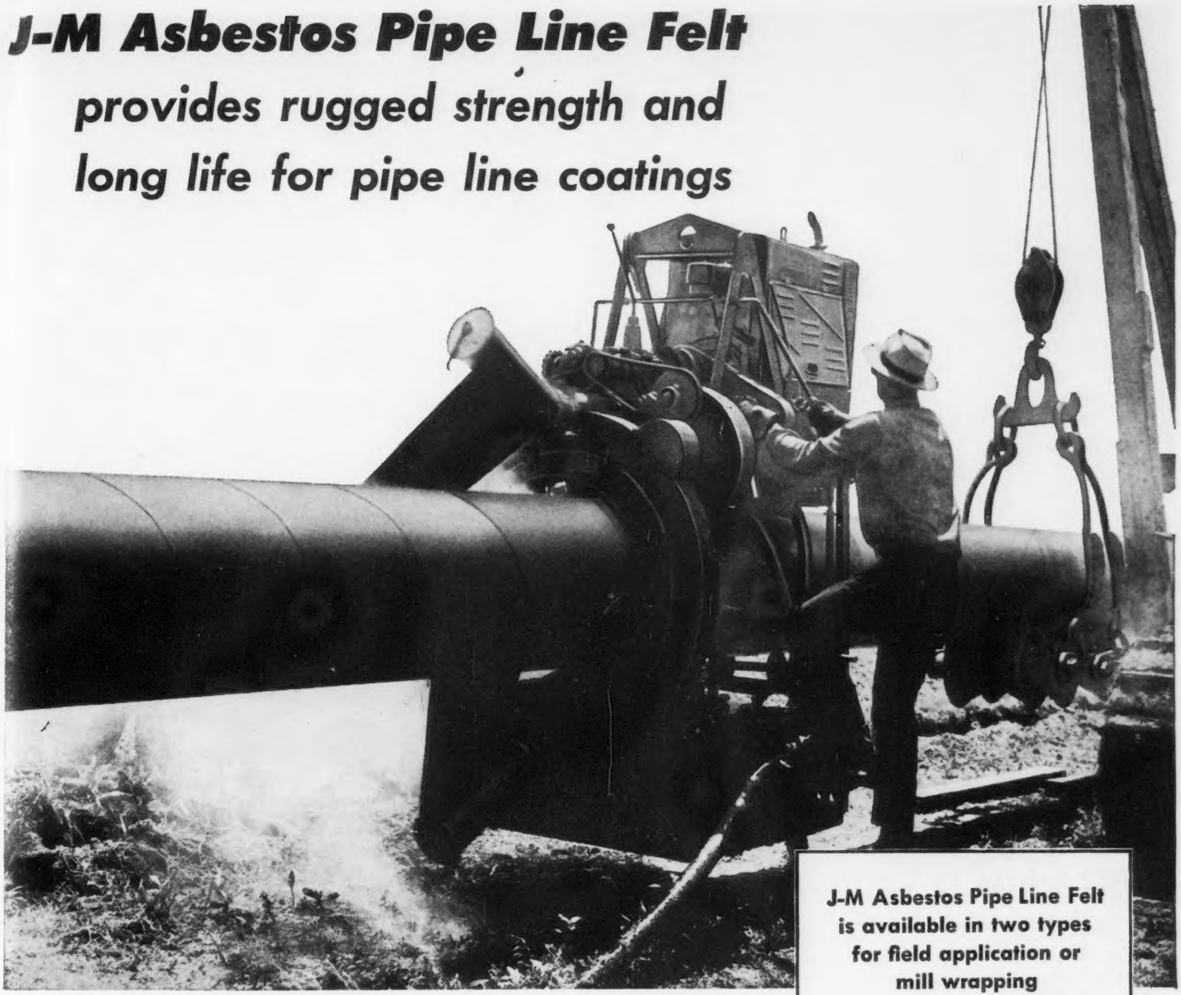

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CANADIAN REGION'S recent meeting in Edmonton is shown in photographs above. Top, left and right, some of the social events and bottom, two views of the exhibits on display.

Pyrex Glass Is Central Okla. Section Topic

W. E. Pettigrew, W. H. Curtin & Co. will talk to Central Oklahoma Section on Use of Pyrex Glass in Corrosion Prevention at its May 28 meeting.

Also tentatively scheduled for a November 26 meeting is a discussion titled "Deterioration of Cooling Towers," by Tom Blenkinsop, W. H. & L. D. Betz Co.

The April 23 meeting scheduled Frank Taylor, Otis Pressure Control Co. talking on Corrosion Measurement in Oil Well Tubing.

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AT ST. LOUIS IN MARCH—Top, left to right, Thor N. Rhodin, E. I. duPont de Nemours & Co., Inc., Wilmington, Del., who received the 1957 Young Author's Award; W. F. Rogers, Gulf Oil Corp., Houston, who received the Speller award and Carl Wagner, Massachusetts Institute of Technology, who received the Whitney Award. Bottom, Otto H. Fenner, Monsanto Chemical Co., St. Louis, Mo. reports at the general business meeting on the progress of the conference.

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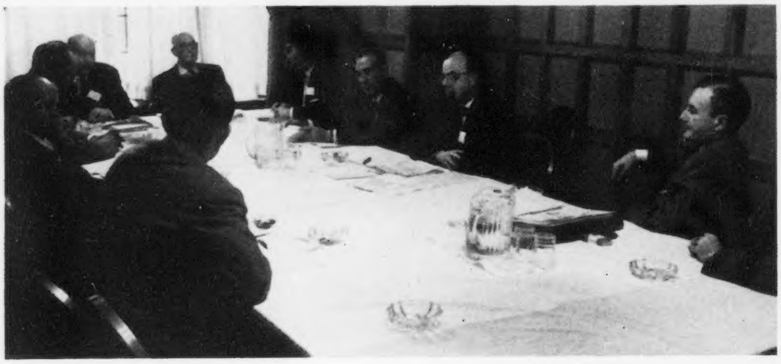

NACE POLICY AND PLANNING committee shown at its meeting during the St. Louis Conference: Identifiable in the photograph, clockwise, R. A. Davis, Chicago Bridge & Iron Co., Birmingham, Ala.; E. P. Noppel, Ebasco Services, Inc., New York, chairman, presiding; A. B. Campbell, NACE executive secretary; Durwood Levy, NACE staff; Vance Jenkins, API; H. P. Godard, Aluminium Laboratories, Ltd., Kingston, Ont. and L. B. Donovan, Consolidated Edison Co. of New York. Guests visible are, left of Mr. Davis, R. F. Haase, Consultant, Milwaukee, Wis.

ST. LOUIS SECTION NACE members and others who participated in a television program broadcast over KETC prior to the recent 13th Annual Conference are, left to right: Norton E. Berry, technical director of the Uranium Division at Mallinckrodt Chemical Works; Edwin F. Trunk, chief engineer, Laclede Gas Co.; Lawrence E. Stout, professor of chemical engineering, Washington University; William A. Bonner, corrosion engineer, Shell Oil Co., Wood River, Ill.

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Piehl

Puckett

Storm

Works

Arrangements Well Under Way for San Francisco Meeting

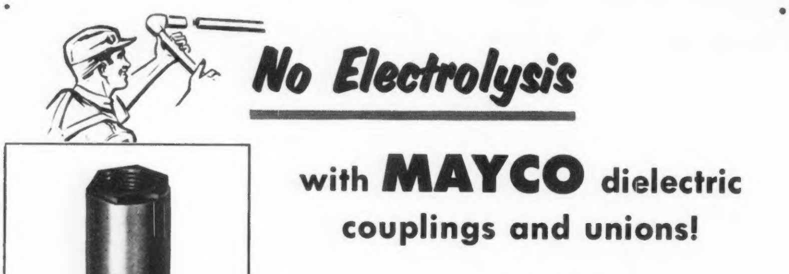
Key personnel have been selected and physical arrangements made for the 14th Annual NACE Conference and Exhibition at San Francisco next March. Roger D. Loper, Standard Oil Co. of California, general conference chairman, reports the arrangements complete for use of the civic auditorium and nearly complete for hotel facilities. Ample accommodations are in sight for all requirements.

Those responsible for on-the-spot arrangements are:

General Conference Chairman Roger D. Loper, Supervisor, Materials Group, Engineering Dept., Standard Oil Company of California. A 1947 graduate of Carnegie Institute of Technology with a BS in metallurgical engineering, he is past chairman of San Francisco Bay Area Section and was program chairman for the 1955 Western Regional Conference.

Assistant General Conference Chairman J. Jackson Puckett, Materials Engineer, The Dow Chemical Co. Western Division. He has a BS in chemical engineering, University of California, 1926; is past chairman of San Francisco Bay Area Section and was registration com-

(Continued on Page 113)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GALESBURG, ILLINOIS

Makers of famous MAYCO Nylon Dielectric Bushings

Kanawha Valley Section Elects Officers for 1957-58

The following were elected to serve as section officers during 1957-58 for Kanawha Valley Section. R. G. Schroeder, Standard Ultramarine & Color Company, chairman; L. T. Moore, Tennessee Gas Transmission Company, vice chairman; William Tufts, Ashland Oil & Refining Company, treasurer; J. E. Brooks, Ashland Oil & Refining Company, secretary.

A. C. Hamstead, Carbide & Carbon Chemicals Company, chairman program committee; Jack G. Brown, Transmission Lines Dept., United Fuel Gas Company, chairman arrangements committee; W. B. Christie, Ben Williamson Company, chairman, membership and hospitality committee; W. A. Koehler, Dept. of Chem. Eng., West Virginia University; and C. B. Weigers, Jr., Allied Services, Inc., respectively chairmen of the by-laws and publicity committee.

Bradford Talks on Coal Tar Epoxies at Shreveport

R. E. Bradford, Plastic Service, Inc., spoke to approximately 50 members and guests of the Shreveport Section on Cold Tar Epoxy Coating Application at the section's March 5 meeting in the Washington-Youree Hotel.

Next meeting was scheduled April 2 at the Washington-Youree Hotel, to feature a discussion of papers presented at the recent NACE St. Louis conference.

Television Script Available

The television script used during a 30-minute program over St. Louis station NETC March 8 is available for inspection at Central Office NACE by those interested in producing a similar program.

Arrangements Well–

(Continued From Page 112)

mittee chairman for the 1955 Western Regional Division Conference.

Exhibits Committee Chairman George A. Works, Assistant Superintendent of Maintenance, Oleum Refinery, Union Oil Co. of Cal. He graduated from University of Colorado in 1940 with a BS in chemical engineering. He is past chairman of San Francisco Bay Area Section.

Program Coordination Committee Chairman Robert L. Piehl, Materials Engineer, Richmond Refinery, Standard Oil Co. of Cal. He is a 1953 graduate of the University of Wisconsin with a BS in chemical engineering.

Publicity Committee Chairman Arthur E. Storm, Assistant Supervisor of Maintenance and Construction, Avon Refinery, Tidewater Oil Co., he has a BS in mechanical engineering from Oregon State College, 1939. He is past chairman of San Francisco Bay Area Section.

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CORROSION is indexed annually in December.

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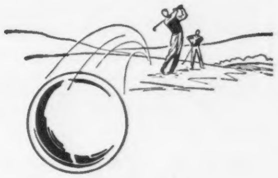

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Resists the Penetration of Water
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More Than 5000 See San Diego Corrosion Exhibit

Public Interest in Corrosion Amazes Section Members

More than 5000 persons inspected or stopped to ask questions at the NACE corrosion exhibit conducted February 21-24 at Balboa Park by San Diego Section. San Diego Section members who staffed the exhibit were amazed at the interest in corrosion problems displayed by the public. Especially notable was the interest shown by women in the display of corroded hot water heaters, a part of the exhibit.

Section members were assisted in booth hospitality by Mrs. Lynn Iba and Mrs. Jan Hepner, wife of Otto Hepner, NACE member. Both received tokens of appreciation from the section at a March 20 meeting.

Among the numerous interesting exhibits were sections of corroded pipes, water heaters, instruments for measuring corrosion, a schematic cathodic protection system; a small motor operated from galvanic current created by coupling dissimilar metals in San Diego Bay muck, wall charts illustrating some types of corrosion protection, literature and others.

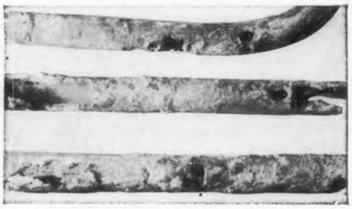
Success of this exhibit has caused the San Diego Section to seriously consider repeating its effort if the affair is held again in future years. The display was part of a number shown at the park during National Engineer's Week.

NATIONAL ASSOCIATION CORROSION ENGINEERS
CATHODIC PROTECTION SYSTEM

CORROSION ENGINEERS

SAN DIEGO SECTION'S exhibit during the recent Engineer's Week at Balboa Park shown above was visited by about 5000 persons during the period February 21-24. Top: Father and two sons examine an operating display. Table shows corroded water mains, gas mains and pump parts. Hostess Mrs. Otto Hepner is seated at left. Center: Interested visitors get answers from Dallas Raash, Helix Irrigation District, and others. On table at rear underneath the word "National" a small motor is running from current produced by corrosion of dissimilar metals in San Diego Bay muck. Right, Dallas Raash explains exhibit to hostess Lynn Iba and Member Otto Hebner, San Diego Water Dept. Exhibit measured current available to a protected surface compared to an unprotected surface. Measuring cell was motor operated and passed slowly from protected surface to unprotected surface as meter registered the current. This display attracted much attention and evoked many questions.

CORROSION PROBLEMS?



SULFUR, VANADIUM, AND SODIUM, FROM THE FUEL OIL CAUSED THESE BOILER TUBE FAILURES

BARSAD FUEL TREATMENT PREVENTS THIS CORROSION

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Pat. Pending

FOR DETAILS WRITE
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LARCHMONT, N. Y.

All-American Canal, Telephone Cable Corrosion Problems Discussed at San Diego

Corrosion problems of and solutions on the All-American Canal in Imperial Valley were described to 35 members and 26 guests of San Diego Section at a March 20 dinner meeting at LaMesa, Cal. David T. Jones, Pacific Telephone and Telegraph Co., North Hollywood, Cal. talked on "Corrosion of Underground Telephone Cables—Some Problems Encountered and How They Are Corrected."

Charles Youngstrom, Imperial Irrigation District, Brawley, Cal. gave a detailed description of corrosion problems on the All-American Canal. He explained and illustrated with slides the gates, settling basins, silt sweeps and explained problems connected with handling raw Colorado River water. Varieties of cathodic protection systems and coatings are employed, he said.

Mr. Jones' talk covered problems associated with telephone cables in conduits. Slides illustrated the lecture.

A brief report on the NACE exhibit at Balboa Park was made by Reuben Tullis, Escondido Mutual Water Co., Escondido, Cal. and Richard Whidden, Convair reported on a contemplated short course on basic corrosion.

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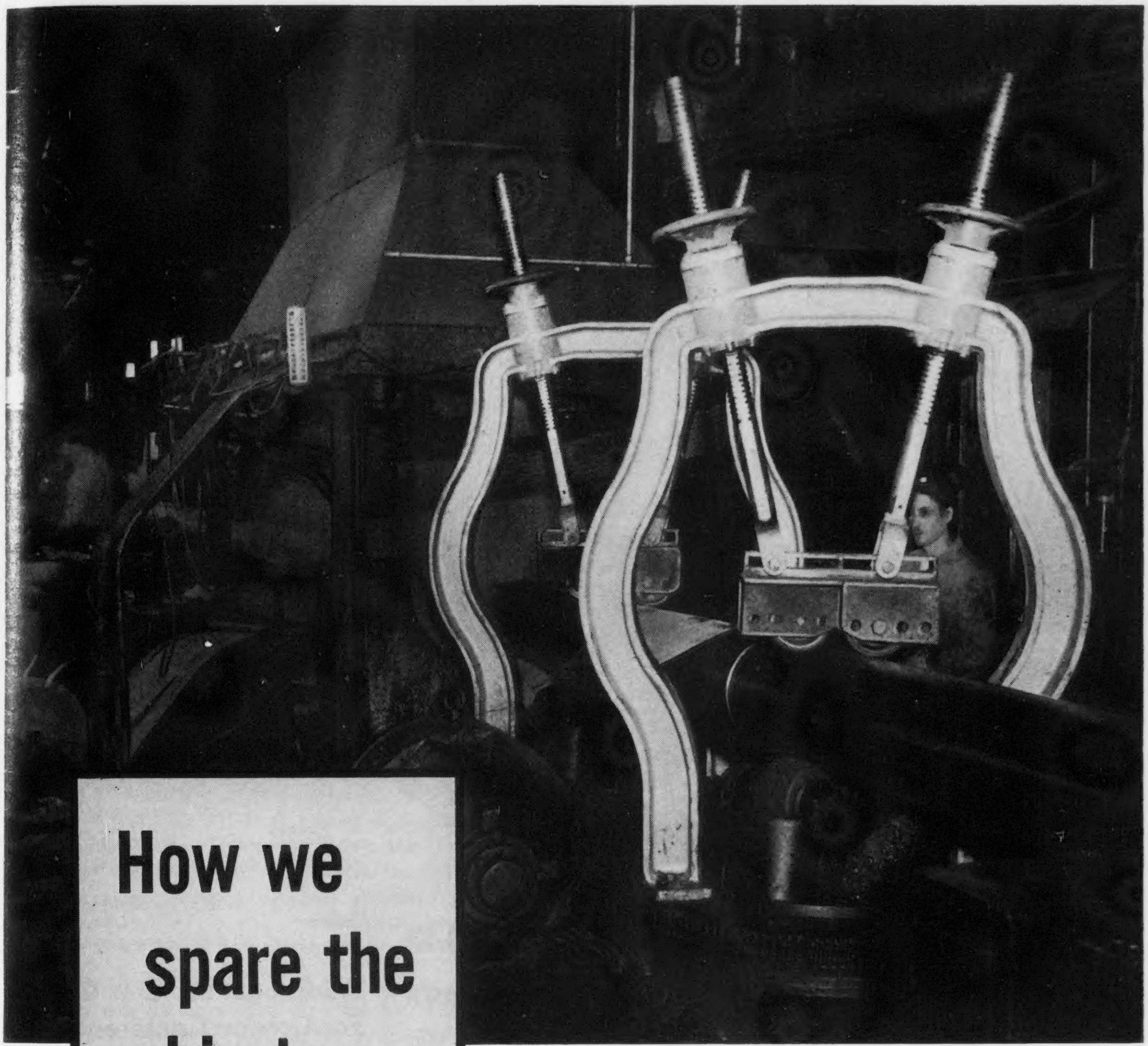
Exhibitions will be held at NACE regional meetings in Oklahoma City and Chicago this fall.



How we spare the whip to protect your pipe

You know how the bearings prevent crankshaft whip in your car. Hill-Hubbell took the same principle, adapted it to the pipe wrapping business. Thus the giant double yoke shown above, grips and steadies pipe as it is fed spirally into the coating-wrapping machine. This prevents whip, eliminates any irregularity in the thickness of the coatings or the tension of the wrappings. The "whip preventer" is another Hill-Hubbell first, another reason to—

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Basic Corrosion Course Considered at San Diego

A short course on basic corrosion is under consideration by San Diego Section. If plans mature it is scheduled to be held during September, designed to benefit plumbers, building maintenance men, tuna and other boat owners, maintenance workers and boat repair men; some categories of aircraft workers and others who need the training. The course will be limited to 30 students and will be held in 2-hour sessions once a week for four weeks.

A proposed general outline was suggested as follows:

Introduction to corrosion. What it is, does. Course subject material, basic terminology and basic electricity, chemistry and metallurgy.

Dissimilar Metal Corrosion. Types of metals, uses, refining, limitations. Examples of galvanic corrosion. Electromotive series.

Chemical Corrosion. Causes, catalysts, aggressive environments, water chemistry. Discussion of types of corrosion found in water heaters, piping, valves, pumps, marine structures and aircraft.

Types of Protection. Cathodic protection, alloys, coatings.

Papers Are Reviewed

Papers heard and new products seen at the March NACE Conference were described by Ned Stearns, D. E. Stearns Co. to about 35 members of Shreveport Section April 2.

NACE MEETINGS CALENDAR

May

2 Pittsburgh Section. Specifications and Testing of Tank Linings, W. P. Cathcart, Tank Lining Corp. Mellon Institute.

10 Philadelphia Section. Walter Luce, The Duriron Co. Poor Richard Club.

15 Greater Boston Section. Spectographic Analysis to Detect Corrosion, Linwood Eikren, Baird Associates. Election of officers. Hotel Beaconsfield.

16 Detroit Section. Demonstration and lecture on microwaves, transistors and the solar battery, Herbert Bumpus, Michigan Bell Telephone Co.

16 Kanawha Valley Section. Titanium—Fabrication and Corrosion Resistance, William Lusby, E. I. duPont de Nemours & Co., Inc. Topette Drive In, Route 60.

21 Chicago Section. Value of NACE Membership, W. F. Fair, Jr., Koppers Co., Inc., NACE past-president. A film on laying a water line in Colorado will be shown also.

21 Cleveland Section. Epoxy Resin Coatings, Ralph Madison, Truscon Laboratories.

23 Sabine-Neches Section. Importance of Human Relations in Industry. Little Mexico Restaurant, Orange, Texas.

27 Central Oklahoma Section.

No date—North Texas Section, annual picnic.

Lehigh Valley Section. Plant tour.

June

25 Central Oklahoma Section.

Additional Lectures Given For Gordon Conference

Discussions in addition to those previously reported (CORROSION, March, 1957 Page 136) to be held during the Gordon Research Conference on Corrosion July 15-19 at Colby Junior College, New London, N. H. are as follows:

July 16—Structure-Dependent Corrosion and Oxidation. D. A. Vermilyea, chairman.

Structural Relationships of Oxide and Metal in Oxidation, K. R. Lawless, University of Virginia.

Structural Factors Associated With the Oxidation of High Purity Aluminum in Water, W. E. Tragert, General Electric Co.

Structure Dependent Oxidation Processes, Earl Gulbransen, Westinghouse Electric Corp.

July 17—Corrosion in Water at High Temperatures. E. C. W. Perryman, chairman.

The Proton and Aqueous Corrosion at High Temperatures, R. A. U. Huddle, Atomic Energy Research Establishment, Harwell, England.

W. D. Robertson, Yale University, is chairman and J. E. Draley, Argonne Laboratory, vice-chairman of the conference.

New RUBEROID PIPELINE SHIELD

means extra safety in extra tough areas

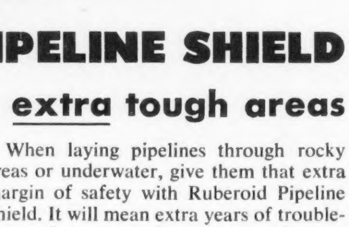
V.I.P.'s (Very Important Pipelines) take an extra beating in mountain cuts and river crossings from rock abrasion and penetration. The standard covering of felt and enamel is not enough to insure long, maintenance-free performance. In such areas, Ruberoid's new Pipeline Shield is the made-to-order extra protection that pipelines need.

Pipeline Shield is made of two or three-ply premium felt impregnated with bitumen. It's extra tough and durable to withstand extremes of abrasion and penetration . . . to keep lines operating without costly interruptions for repair.

Pipeline Shield is easy to apply right over the felt outer covering. Available in 5′ lengths . . . in widths from 12″ to 116″ to fit any size pipe. One or two man crews can quickly install it with 1″ metal strapping. Seals (660 per 1000′) are just as simple to install.

When laying pipelines through rocky areas or underwater, give them that extra margin of safety with Ruberoid Pipeline Shield. It will mean extra years of trouble-free performance in those extra tough areas.

METHODS OF APPLICATION



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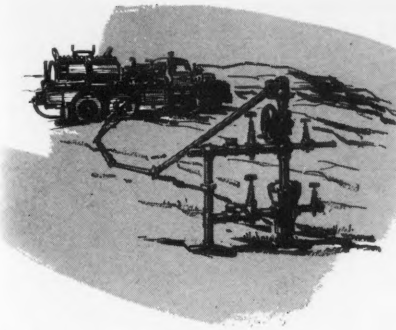

REPORT ON A NEW CONCEPT IN CORROSION CONTROL

For Oil and Gas Wells

CORBAN®, the polar-type corrosion inhibitor developed by Dowell, has proved its effectiveness in hundreds of wells. Now, a different concept in the use of liquid inhibitors has been developed. In this method, Corban is not merely put in the well; it is pumped back into the producing formation. Then it returns slowly to the well bore along with normal oil production. Continuous protection is thus given to all metal equipment for a period of months.

So far, results have been outstanding. The following case history is an example of the results obtained with this new method.

this is an engineered approach all the way

> *A gas-lift well in South Texas was producing 25 BOPD and 85 BWPD from the Frio sand. The well was equipped with 1-inch tubing containing gas lift valves inside 2½-inch J55 production tubing. The 1-inch tubing extended to a depth of 2001 feet; total depth of the well was 5547 feet. A packer was set at 5482 feet. At 2468 feet, the 2½-inch tubing was swaged to 2-inch tubing. Severe corrosion was found to be at the swage, 467 feet below the bottom of the 1-inch tubing. It was doubtful that inhibitor applied in the conventional manner would reach even the bottom of the 1-inch tubing.*

Corban was then pumped into the formation. Ten gallons of concentrated Corban 101 were mixed with 12½ barrels of salt water. Since this one treatment, water produced by the well has been analyzed several times. The following table shows the results.

check this economy— only 10 gallons of Corban used

Date	Iron, Parts Per Million	Remarks
4-6-56	132	Just prior to described treatment
4-11-56	41	First test after treatment
4-17-56	80	Second test after treatment
4-25-56	55	Third test after treatment
5-14-56	27	Fourth test after treatment
6-6-56	23	Fifth test after treatment Iron content reduced 83% at this time
9-1-56	37	Sixth test after treatment Iron content still reduced by 72% compared to that before treatment

Compare these results with conventional methods

Corban is available in both stick and liquid form, in a formula suited to your well. Call any of the 165 Dowell offices in the United States and Canada; in Venezuela, contact United Oilwell Service. Or write Dowell Incorporated, Tulsa 1, Oklahoma.

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NATIONAL, REGIONAL MEETINGS and SHORT COURSES

1957

May 20-22—Northeast Region Corrosion Control Conference, Syracuse University, Syracuse, N. Y.

Oct. 1-4—North Central Region, Chicago, Sherman Hotel. Exhibition.

Oct. 1-4—South Central Region, Oklahoma City, municipal auditorium. Exhibition.

October 23-25—Western Region. Seventh Annual Conference, U. S. Grant Hotel, San Diego, Cal.

Nov. 12-14—Northeast Region Fall meeting, Pittsburgh, Pa., Penn-Sheraton Hotel.

1958

Mar. 17-21—NACE Annual Conference, Civic Auditorium, San Francisco, California.

October 5-8—Northeast Region, Somerset Hotel, Boston, Mass.

October 20-24—South Central Region. New Orleans, Roosevelt Hotel.

1959

NACE Annual Conference, Sherman Hotel, Chicago, Illinois.

SHORT COURSES

June 6-7—Teche Section Short Course on corrosion. Southwestern Louisiana Institute, Lafayette, La.

October 22-23—Western Region. Corrosion Control Course (Evening Sessions) Hotel U. S. Grant, San Diego, Cal.

147 Brave Bad Weather to Attend Okla. Univ. Course

Bad weather failed to daunt 147 persons who registered for the Fourth Annual Corrosion Control Short Course held April 2-4 on North Campus of University of Oklahoma. The university and Central Oklahoma Section NACE cooperated in presenting the course.

Storms and transportation delays did not prevent registrants from attending from Casper, Wyoming; Chicago; Des Moines, Washington, D. C. and Beatrice, Neb.

R. J. James, University of Oklahoma, chairman of the event reported the lectures well prepared and presented and the audience consistently attentive. Panel discussions were considered very successful.

Kenneth McFarland to Speak At Oklahoma City Luncheon

Kenneth McFarland, educator and nationally known speaker, who is with General Motors Corp., will be guest speaker at the October 3 South Central Region Annual Business Luncheon. Dr. McFarland, variously known as "America's No. 1 Air Passenger" and as a "PhD with Horse Sense" because of his activity raising Tennessee walking horses at his farm near Topeka, Kansas, is an educational consultant to General Motors.

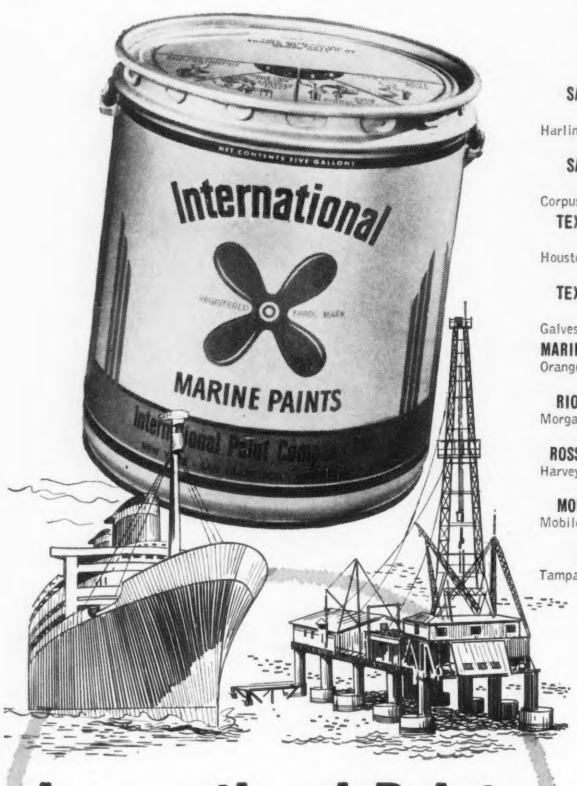
The luncheon will be a feature of the 1957 South Central Region meeting at Oklahoma City.

Dr. McFarland, a graduate of Pittsburgh State College, Kansas, with a master's degree from Columbia and a PhD in education from Stanford University is in constant demand as a speaker before business groups. He is said to have addressed as many important meetings of educators as any other American.

NACE Editorial Review Committee Adds 7 Members

Seven members have been added to the NACE Editorial Review Subcommittee, bringing to 17 the number now reviewing manuscripts submitted for publication in CORROSION. It is expected several more members will be added soon.

New members of the subcommittee are: Mark F. Adams, State College of Washington, Pullman; Joseph Bigos, U. S. Steel Corp., Monroeville, Pa.; Frank E. Kulman, Consolidated Edison Co. of N. Y., Inc., New York; Charles C. Nathan, The Texas Company, Houston; Jane H. Rigo, American Steel & Wire Co., Cleveland; A. H. Roebuck, Continental Oil Co., Ponca City, Okla.; Robert A. Woofter, Jones & Laughlin Steel Corp., Pittsburgh, Pa.



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*Calgon is the Registered Trade Mark of Calgon, Inc. for its glassy phosphate (sodium hexametaphosphate) products.

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Procedure in the Selection of Persons to Receive the Willis Rodney Whitney and Frank Newman Speller Awards

As Approved by the Board of Directors, December 4, 1953, and Revised March 6, 1955.

The board of directors of the National Association of Corrosion Engineers in a regular meeting on January 17, 1947 authorized the presentation annually of two awards by the association.

The Willis Rodney Whitney Award is given in recognition of public contributions to the science of corrosion. A contribution to science is defined as the development of new information or the development of a more satisfactory theory which contributes to a more fundamental understanding of corrosion phenomena.

The Frank Newman Speller Award is given in recognition of public contributions to corrosion engineering. A contribution to engineering is defined as the development or improvement of a method, apparatus or material by which the control of corrosion is facilitated or made less costly.

Committee Appointment

Not later than May 15th of each year and preferably in advance of the annual conference, the president (or president-elect) for the year in which the award is to be made, in consultation with the immediate past president for this same year, shall appoint an awards committee. This committee shall consist of at least six members with the immediate past president of the association (as referred to above) serving as chairman. In the event the immediate past president should be unable to serve, the president (for the year the award is to be made) shall appoint a chairman. The other members of the committee should be outstanding members of the association. At least two but not more than four members of the awards committee should be re-appointed from the awards committee of the preceding year. No member shall serve on the awards committee for more than two years in succession. Any member who is lost by the committee through resignation or for any other reason, shall be replaced by appointment by the president of the association.

The chairman of the awards committee shall arrange to keep reasonably detailed records of the activities and discussions of the committee. These records shall be made available to succeeding awards committees.

Candidates to Be Considered

The list of candidates to be considered for the awards shall include:

A. The names of those proposed but who did not receive awards in the two immediately preceding years.

B. The names of all those proposed in previous years who in the judgment of the committee members should be retained on the list regardless of the year proposed.

C. The names of those proposed by the chairmen of the regional divisions in accordance with the wishes of the members of the division. Nominations may be made by local sections or may be proposed directly to the chairman of a region by individual members. In any case, nominations should be accompanied by an appropriate statement of the basis of the proposal. This statement shall be reproduced and submitted to all members of the awards committee. The committee should have such statement for all nominees to be considered.

NOTES FOR GUIDANCE OF AWARDS COMMITTEE

A. The committee shall not recommend the same individual for both awards in any one year.

B. Previous recipient of an award is not eligible to receive the same award again.

C. The recipient of one award is not barred from receiving the other award for some other year.

D. In considering the qualifications of those nominated for awards, the nominee's total contributions should be taken into account and recent activities should not take precedence over the recognized results of earlier work. Other things being equal, awards should be made to the candidates who have been contributing consistently for the longest period.

E. Candidates need not be residents of North America.

F. Candidates need not be members of the National Association of Corrosion Engineers.

G. Awards shall be limited to living persons.

H. Recipients of the Willis Rodney Whitney and the Frank Newman Speller Awards and the recipient or recipients of the Junior Award should be guests at the annual NACE banquet.

I. The president and vice president of the association and the chairman of the awards committee should not be considered as candidates for awards.

Prior to June 1st of each year the regional chairmen shall forward to the chairman of the awards committee all names proposed for awards, accompanied in each case by summaries of the reasons presented in support of each proposal but with no indication of the number of duplicate nominations of any individual. The object of this latter provision is to insure that awards will be made on a basis of accomplishments and other qualifications rather than by any semblance of a popular vote.

Not later than April 1st (or the publication date of April issue of CORROSION) of each year the executive secretary shall notify the membership, either by direct letter or through publication in CORROSION of their privileges in this regard as set forth here.

D. Any names proposed by the members of the committee prior to June 1st of each year.

At the discretion of the committee members the resultant list of candidates may be reduced to a workable number by elimination of those known to lack the necessary qualifications.

Contributions Are Listed

As a basis for further consideration by the committee, the headquarters staff of the association shall provide the committee, through its chairman, with a record of the contributions of each final candidate in the form of a list of his published papers and other works. Such records available in the headquarters office may be supplemented by additional information on the candidates' qualifications which may be secured by any member of the committee from other sources, such as friends of the candidates and especially from the proposers of the candidates who should be asked to provide their reasons for suggesting them and a summary of their accomplishments. Ordinarily, the candidates should not be made aware that they are being considered for awards by seeking such information from them directly.

The required activity of the headquarters staff should be facilitated by appropriate use of the literature abstract filing system.

The list of candidates about whom the headquarters staff is to provide the information described, should be sent by the chairman of the committee to the executive secretary of the association and to each member of the committee not later than July 15th.

The information to be provided by the headquarters staff should be sent by the executive secretary to the chairman and each member of the committee not later than September 1st.

Information secured by any member of the committee concerning any candidate or candidates should be sent to the executive secretary not later than August 15th so that it can be circulated amongst all the members of the committee not later than September 1st.

Not later than October 1st, each member of the committee shall submit to the chairman and by copy to each member of the committee, his first and second choice nominations for each award and shall provide with his nominations, his appraisal of the qualifications of those he is nominating and his reasons for preferring them. If a member of the committee feels that no award should be given, he should so state by October 1st. Failure to nominate either a first or second choice for either award will not relieve a committee member of the duty of voting on the nominations made by others, or of voting that no award be made if those nominated are not considered satisfactory.

Between October 1st and November 15, the chairman shall arrange for an election by the committee of those to be nominated for the awards. As a general rule, this should be preceded by a meeting of as many of the members of the committee as can be assembled for first-hand discussion of the qualifications of the candidates, but, in any event, the selection shall be made by letter ballot. If no decision can be made by the first ballot, then a second ballot shall be

(Continued on Page 121)

Procedure in the—

(Continued From Page 120)

taken on those who have received the most and second most votes on the first ballot. In the event of a tie for first place on the first ballot, only those names shall be considered in a second ballot. Similarly, in the event of a tie for second place, these names, plus the first place name, shall be considered on a second ballot. In the event a person is nominated for both awards, his vote for one award shall not be considered in determining his standing in the vote for the other award.

If the committee should decide that none of those nominated are worthy of the awards, or if no nominations are received, the committee may recommend to the directors that one or both awards be withheld for reasons to be stated in their report to the directors.

Recommendations of the committee shall be reported by the chairman of the committee to the board of directors through the executive secretary not later than December 1st.

In the event that the committee should be unable to reach a decision on candidates for either or both awards, the committee shall provide the board with a list of all those proposed for consideration and the number of votes received by each on the last ballot of the members of the committee.

The board of directors shall then determine, either in a regular meeting, or by letter ballot, returnable not later than December 15th in each year, whether the recommendations of the awards committee are to be accepted and the awards made as proposed. If the board of directors do not approve the granting of an award, or awards, as proposed by the awards committee, then such award, or awards, will not be made for the year in question. In the event that the awards committee has been unable to reach a decision on candidates for one or both awards, the board of directors shall determine by majority vote whether an award (or awards) shall be made and to whom it (or they) shall be granted.

Presentation of Awards

After the board of directors have chosen the recipients of the awards, the president of the association shall notify the recipients not later than January 15th, and shall invite each of them to be present at the annual meeting or other occasion when the awards are to be presented. The chairman of the committee shall arrange to have appropriate certificates inscribed for presentation to the recipients of the awards and on occasion of any public presentation of the awards he shall present the recipients to the president or whoever may be serving in his stead as chairman of the meeting, to receive the awards at his hands.

The actions of the awards committee shall be confidential and confined to consideration only as outlined in the procedure until such time as the president receives acceptance or rejection from the awardees following his notification to them. After receiving acceptance of an award or awardee, the president shall so notify the executive secretary who may publicize the information prior to the actual presentation of the award or awards.

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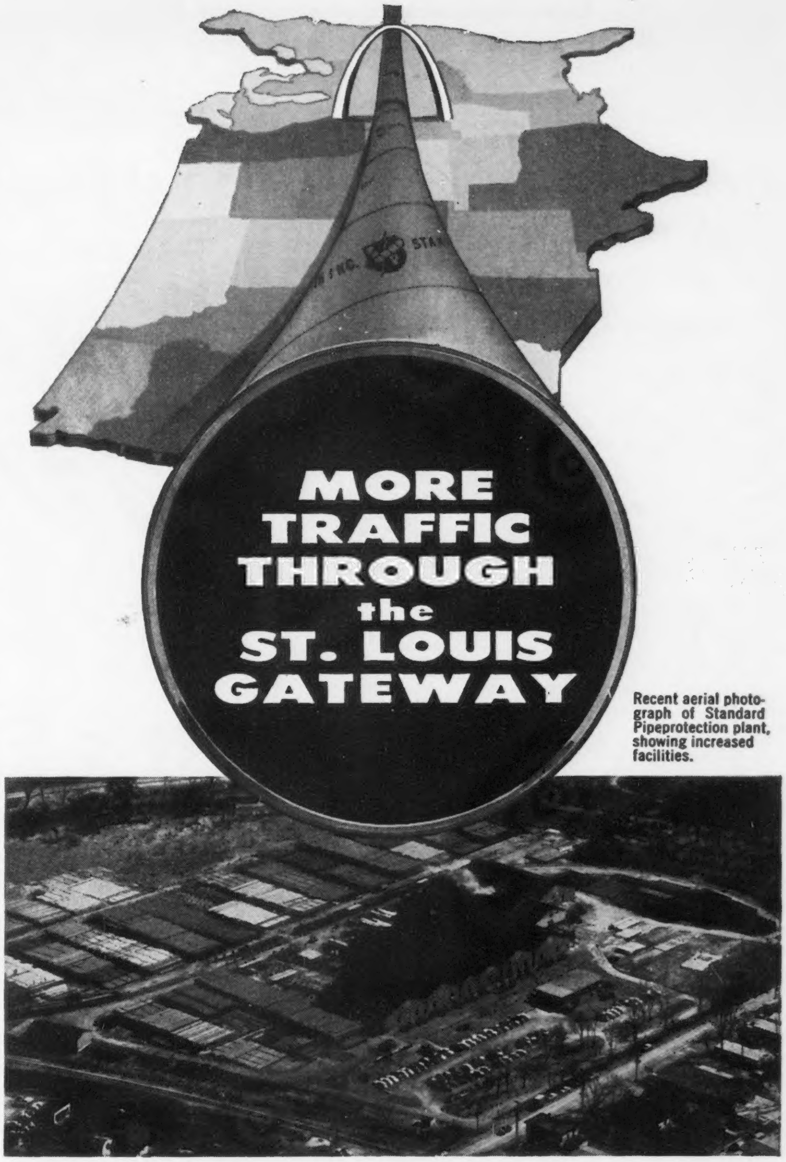
The NACE Abstract Filing System is used by many organizations.


MORE TRAFFIC THROUGH the ST. LOUIS GATEWAY

Recent aerial photograph of Standard Pipeprotection plant, showing increased facilities.

Each successive year more pipe passes through the St. Louis Gateway, where at Standard Pipeprotection it is coated and wrapped according to procedures that establish the highest standards of quality for pipe protection.

This increased traffic has necessitated the erection of extra pipe storage areas with greater capacity, additional railway sidings, new coating and wrapping machines, much larger parking areas, more roads for truck deliveries and enlarged office space.

The benefits you receive from SPI coated and wrapped pipe have resulted in more business for us.

standard pipeprotection inc.
3000 SOUTH BRENTWOOD BLVD. • ST. LOUIS 17, MISSOURI

This is one way to protect pipe lines from rust and corrosion but . . .

It's Easier and Cheaper with UNICOR®

UNICOR, UOP's oil soluble corrosion inhibitor, gives dependable protection at suprisingly little cost. Actually only one molecule of Unicor is required for every million molecules of pipe line product. Its cost is only about $0.0005 per barrel of product.

It's economical to apply, too. Addition is made at only one point and since it is distributed evenly over the entire internal surface, protection is virtually 100% effective. There are important additional savings, too, from reduced scraper cleaning and filter replacement costs.

We will be glad to have our technical specialists assist you in the design, installation and operation of a Unicor system of protection.

UNICOR is one of a number of UOP inhibitors and additives available to the refining industry. If you have a protection or preservation problem for product or transport facilities consult us.

PRODUCTS DEPARTMENT

UOP®

UNIVERSAL OIL PRODUCTS COMPANY

30 ALGONQUIN ROAD, DES PLAINES, ILLINOIS, U. S. A.

GENERAL NEWS

Acid Resisting Porcelain Best in 15-Year Tests

Panels Completely Covered Show No Corrosion Damage

The National Bureau of Standards has recently completed a 15-year weather exposure test of porcelain-enameled steels. Since 1939, the Bureau has been conducting investigations of the weather resistance of such enamels by exposing a large number of samples to four climatic conditions, representative of different parts of the eastern United States. The investigation was carried out by D. G. Moore and W. N. Harrison of the Bureau's enameled metals laboratory.

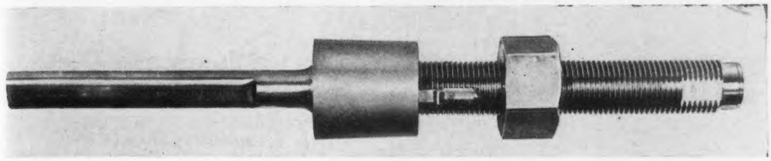
Large variations were found in the weather resistance of the various enamel types investigated. The enamels affected least by the exposure were those having high resistance to acid attack. The most resistant enamels retained more than 90 percent of their initial gloss and showed insignificant color changes (less than 1 NBS unit) while some of the enamels of poor acid resistance (which were not of a type recommended for outside exposure) changed from full gloss to a dull finish in 15 years.

A basic function of the porcelain enamel is to prevent corrosion of the base metal; hence, all of the panels were inspected for evidence of corrosion of the steel base. After 15 years of exposure it was found that, where the initial coverage was complete on all parts of the panel, no corrosion occurred regardless of the type of enamel applied. However, on many panels the reverse side was protected with only a single ground-coat application. In these cases good coverage of the metal was not always achieved, especially where the specimens had rested on support points during firing. Corrosion started at these points of poor coverage and spalling of the enamel on the face side opposite the poitns occurred after the corrosion had progressed only part way through the steel. These spalled areas were more prevalent under the corrosive "salt-air" conditions of Atlantic City than at three other locations.

Weather resistance of the enamel surface was evaluated by measuring the changes in the specular gloss and in the color. Such measurements showed that variations in climate had only a minor effect on the weathering behavior of most of the enamels. The same measurements showed that, on the average, the compositions that were highly resistant to attack by acid solutions were also resistant to the action of weathering.

The four selected sites all have fairly high annual rainfalls. Since weathering action is dependent on moisture, surface deterioration would be expected to proceed at a slower rate in a dry climate

(Continued on Page 124)



TITANIUM THERMOWELLS, such as that above made by Rem-Cru Titauium, Inc., Midland, Pa. are expected to last as long as five years in an environment in which 18-8 stainless steel equivalents failed in six months.

Titanium Thermowells Save $3000 a Year

Substitution of titanium for 18-8 stainless steel thermowells exposed to dilute nitric acid and nitrogen oxide over 400 F is estimated to have saved E. I. duPont de Nemours & Co., Inc., as much as $3000 a year.

The titanium thermowells, costing $300 versus the $95 for stainless steel equivalents have been in service a year with no indication that there has been any corrosion. Stainless steel units in the same service failed usually about every six months at a cost in labor and lost production of about $1500 for each failure. It is estimated the titanium units will last for about five years, which would mean a saving on the order of $13,500 during their life versus the stainless steel.

Using a basis of comparison estimating material costs to be about 20 percent of a finished unit, the cost differential between titanium and Type 316 stainless steel, for example, may be as little as 3 times although the material cost differential per pound is 17.

Four Atmospheric Test Sites Selected by ASTM

Sites at Point Reyes, Cal., Kure Beach, N. C., State College, Pa. and Newark, N. J. have been selected for atmospheric exposure testing by Committee B-3 on Corrosion of Non-Ferrous Metals and Alloys of American Society for Testing Materials. A decision to start a new series of tests to include many of the newer alloys and some metals such as titanium was made during the February 4-8 ASMT Committee Week at Philadelphia.

Plans call for removal of specimens at the end of two, seven and up to 20 years.

An eight year program of calibrating various exposure sites in North America has been completed and data will be published soon on corrosivity of the various locations.

The committee continues to collect data concerning salt fog and other accelerated tests.

100% Electrical Inspection Assures Quality of Tape

An instance in which electrical inspection of a dielectric material has moved inside and been made a routine procedure is revealed by the Polyken Products Department of the Kendall Co., Chicago. The calendered polyethylene tape made by Polyken is inspected by a holiday detector developed for the company by Tinker & Rasor, San Gabriel, Cal.

The front cover illustration of this issue of Corrosion shows a multiple spark passing between electrodes of this detector and through an intentional holiday in the film made for the purpose of taking the photograph. Ordinarily, holidays are detected by a single spark because of the nature of the pulse and speed with which the tape passes the inspection bar.

Polyken's justification for this inspection is seen in recent reports[1,2] in which the material has proved superior in the field.

The holiday detector used was developed specially to provide inspection which would be essentially the same as that given the tape in the field, after it has been applied to pipe. The machine is designed to continuously inspect and record the total number of pinholes or imperfections as the material passes the electrode. The voltage generator produces pulses of very short duration because the type of energy produced has a minimum stress effect on the film and reduces the tendency of the material to break down later.

The recording system indicates the total number of spark discharges and remote signalling makes it possible for the operator to be alerted each time a spark is discharged. An oscilloscope permits operators to observe the shape of the electrical wave and a camera records its shape for future reference.

This electrical inspection is one of the many quality control procedures observed by the company, including thickness control, temperature, tensile strength, tack, adhesion, elasticity and other physical characteristics.

References

1. Paul Reed. *Oil and Gas Journal.* Page 70. Nov. 26, 1956.
2. Donald M. Taylor, *Petro. Eng.* Page D-33, Nov., 56.

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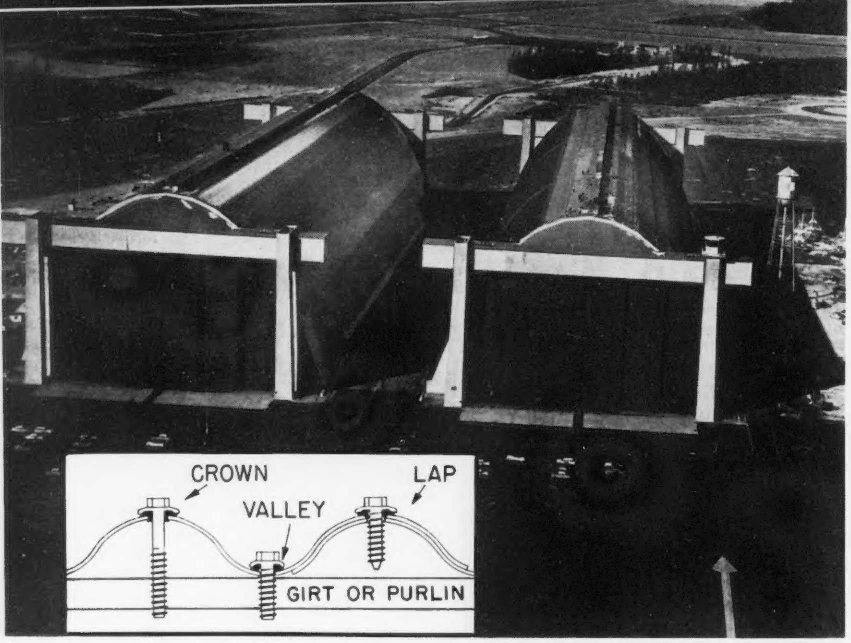
The 10-Year Index to Corrosion, published in 1956, contains more than 4000 reference phrases to material in issues published 1945-54 inclusive.



STAINLESS STEEL SCREWS with integral neoprene washers were used to fasten a million square feet of aluminum alloy corrugated sheets to roof these World War I hangars at U. S. Naval Air Station, Lakehurst, N. J. The fasteners, made by Townsend Co., New Brighton, Pa. helped solve a costly maintenance problem by providing a roof designed to withstand 120-mile winds; resist salt spray, give a water-tight seal and guarantee a high tear point. Successful use of the fasteners is expected to result in the addition of aluminum roofs to 20 blimp hangars throughout the nation.

Extensive Air Pollution Data Are Presented At Los Angles Meeting of APCA Section

Extensive technical data on air pollution and its control were presented during the First Technical Meeting of the West Coast Section, Air Polution Control Association, at Los Angeles, March 25-26. Among the technical papers presented were:

Air Pollution Problems Arising from Usage of Liquid and Gaseous Hydrocarbons, Hoyt R. Crabaugh, Los Angeles County Air Pollution Control District.

Significance of Contaminants From Central Station Power Plants, Albert L. Chaney, Chaney Laboratories.

Problem of Sulfur in Residual Fuels, Gerald Fisher, Western Oil and Gas Association.

Removal of Particulate and Gaseous Contaminants from Power Plant Flue Gases, Arie J. Hagen-Smid, California Institute of Technology.

Effects of Design Factors on Stack Emissions from Multiple-Chamber Incinerators, Ralph E. George, Los Angeles County Air Pollution Control District.

The Organic Solvent Problem in Air Pollution, Carl V. Kaner, Los Angeles APCD.

Oxidant Forming Characteristics of Organic Solvents, Margaret M. Fox, Los Angeles APCD.

Control of Organic Solvent Emissions from Industrial Processes by Catalytic Adsorption, D. F. Morgan, Union Carbide and Carbon Corp.

Control of Organic Solvent Emissions from Industrial Processes by Catalytic Combustion, Bert L. Gamble, Continental Can Co.

Motor Exhaust Composition in Relation to Selected Fuels, Leslie A. Chambers and Paul P. Mader, Los Angeles APCD.

Direct Fired Afterburning Mufflers, George E. Mead, Clayton Manufacturing Co.

Numerous panel discussions in the areas represented by the technical papers also were held.

ASTM Adopts New Method Of Air Sample Recording

Methods of continuously recording air pollution were considered by American Society for Testing Material's Committee D-22 on Methods for Atmospheric Sampling and Analysis during February Committee Week sessions at Philadelphia. The committee approved an alternate method for continuous recording of sulfur dioxide known as the electrolytic method to be added to the conductivity method already published (ASTM Method D1355).

A method of continuous recording of fluorides is under study.

High School Chemistry Teachers Have Paint Course

A "Paint Short Course for High School Chemistry Teachers" will be conducted June 25-July 2 at North Dakota State College, Fargo. Sponsored by the Federation of Paint and Varnish Production Clubs, it is designed to assist high school chemistry teachers in interesting their students in the paint industry. Each of the Federation's clubs will select a teacher to attend the session to be conducted by Wouter Bosch, Chairman of the Dept. of Paints, Varnishes and Lacquers at NDSC. All fees are underwritten by the federation.

Lectures for June 4-6 Appalachian Short Course Are Listed

Programmed lectures on the Second Appalachian Underground Corrosion Short Course to be given June 4-6 at Mineral Industries Building, West Virginia University, Morgantown are as follows:

Tuesday, June 4

Fundamentals of Corrosion, W. A. Koehler and staff, West Virginia University.

Visual Demonstration and Discussion of Corrosion and Cathodic Protection, M. C. Miller, Allendale, N. J.

Wednesday, June 5

Demonstration of the Theory of Cathodic Protection, W. J. Kretschmer, Columbia Gas System Service Corp.

Application of Cathodic Protection, D. A. Tefankjian, Texas Eastern Transmission Corp.

Coal Tar Coatings, Malcolm Mitchell, Reilly Tar & Chemical Co.

Rectifier Installations and Protection, L. O. McCormick, Baltimore Gas and Electric Co.

Fundamental Analysis of Stray Current Corrosion, Percy Hort, Atlantic Pipe Line Co.

Intermediate Analysis of Stray Current Corrosion, T. S. Watson, Socony Mobil Oil Co.

Asphalt Coatings, F. B. Burns, Kerr-McGee Oil Industries, Inc.

Grounding and Bonding on an Electric Utility System, H. M. Spooner, Public Service Electric and Gas Co.

Cathodic Protection of Well Casing, Y. W. Titterington, Corrosion Services, Inc.

(Continued on Page 126)

Acid Resisting—

(Continued From Page 123)

than at Washington, Lakeland, St. Louis, or Atlantic City. Likewise, in an area of extremely heavy rainfall, the weathering action would undoubtedly be accelerated.

Among the recommendations based upon the findings of this investigation, the one that may prove to be of greatest usefulness for specification purposes states that, for architectural installations where general appearance, absence of fading, and ease of cleaning are important, only those enamels having class A or class AA acid resistance by the standard citric acid spot test[1] should be used. In addition, for enamels containing the cadmium-selenium-sulphur pigment (red, orange, and yellow), only those compositions should be selected that will give a weight loss of less than 1.0 mg/cm^2 when subjected to a boiling solution of 10 percent nitric acid for 2½ hours.

For further technical information, see "Fifteen-year Exposure Test of Porcelain Enamels," by D. G. Moore and W. N. Harrison, a Building Materials and Structures Report of the National Bureau of Standards (in press). For earlier reports of the same investigation see *J. Res. NBS*, 42, 43 (1949) (RP 1949) and **28,** 735 (1942) (RP 1476).

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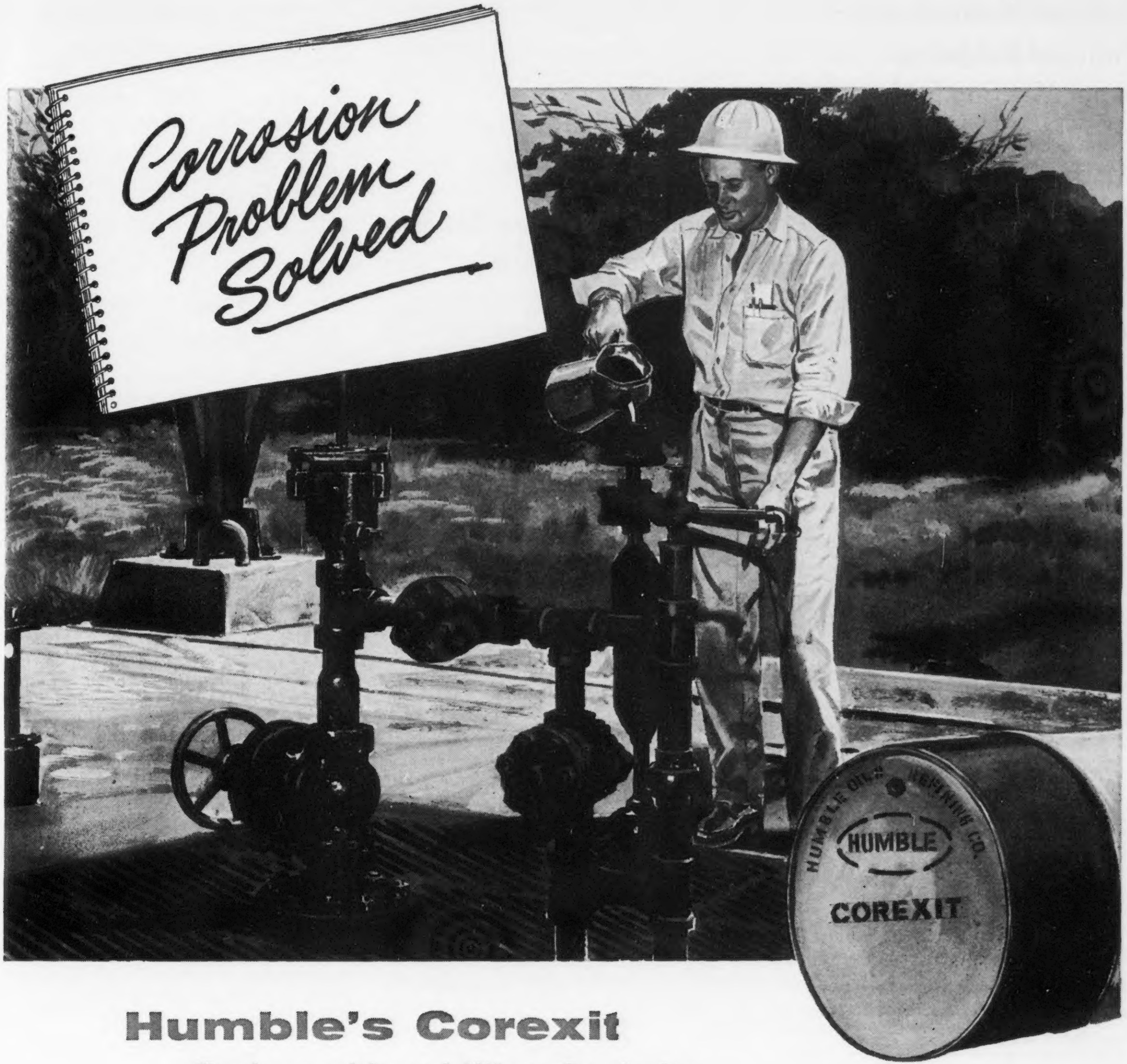
[1] Test for Acid Resistance of Porcelain Enamels; Part I-Flatware. Issued by the Porcelain Enamel Institute, 1145 19th Street, N. W., Washington 6, D. C.



Humble's Corexit

Reduces Your Lifting Costs by Preventing Sub-surface Corrosion

Corexit treatments protect sucker rods and tubing against corrosion and hydrogen embrittlement, even in sour crude wells. Batched down the annulus, *Corexit* works rapidly to clean up your sub-surface equipment, to displace corrosive brine and loose scale from the metal surfaces. Then it builds up a tenacious and durable protective film on these cleaned metal surfaces to prevent further corrosion. Following the initial treatment, the use of a small amount of *Corexit* daily will maintain this tough protective film.

Consequently, you will find lifting costs lower, because *Corexit* prolongs the life of your equipment, and reduces the number of well pulling jobs.

For complete information on *Corexit,* call your nearest Humble wholesale plant in Texas and New Mexico, or write or phone:

HUMBLE OIL & REFINING COMPANY

HUMBLE

Technical Service
Sales Department
Humble Oil & Refining Company
P. O. Box 2180
Houston, Texas

Cathodic Protection Is Principal Subject at Israel Meeting Series

A series of weekly meetings during February and March in Tel Aviv, Israel attracted between 100 and 200 persons, a cross section of industry, water works, telephone, electrical power and agricultural representatives. D. Spector, Nace Member and chairman of the Corrosion Group reported papers given as follows:

Principles of Cathodic Protection, D. Spector.
Measurements in Corrosion Surveys, Y. Berger.
Interference Between Protected and Unprotected Structures, R. Tuwal.
Current Requirements for Cathodic Protection, M. Agew.
Sources of Current for Cathodic Protection, E. Bargil.
Internal Corrosion of Water Mains, M. Carmon.
Pipe Coating and Its Relation to Cathodic Protection, S. Z. Hershkowitz.
Corrosion Prevention—A National Task, D. Spector.

Discussions involved emphasis on cooperative cathodic protection and hot spot protection of old, poorly coated lines.

The group expects to start committee work on specific tasks along the lines used by NACE technical committees.

The 10-Year Index to CORROSION, published in 1956, contains more than 4000 reference phrases to material in issue published 1945-54 inclusive.

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Organizations of corrosion engineers have been founded in England, France, Germany, Italy, Australia, and Japan since NACE was established.

POSITIONS WANTED
and
AVAILABLE

- **Active and Junior NACE members and Companies seeking employees may run without charge two consecutive advertisements annually under this heading, not over 35 words set in 8 point text type.**
- **Advertisements to other specifications will be charged for at $10 a column inch.**

Positions Available

Wanted — Corrosion Engineer — Minimum requirements: BS degree, 5 years' experience in design of corrosion control systems for pipe lines, refineries, marine installations and water systems. Opportunity to head engineering section of large service organization. CORROSION, Box 57-7.

Positions Wanted

Corrosion Engineer and Metallurgist—12 years' diversified experience in steel and chemical industry. Experience includes production, sales and consulting phases of engineering work. Prefer technical field contact work or staff position with opportunity for advancement. Will consider any location. CORROSION, Box 57-5.

Corrosion Engineer, English, 3 years Cathodic Protection including overseas experience. Seeks progressive position anywhere in Canada or America. Available June. CORROSION, Box 57-6.

Armour Foundation Reports Studies on Corrosion

Investigations significant to corrosion workers are reported in the 1956 Annual Report of the Armour Research Foundation of the Illinois Institute of Technology, Chicago as follows:

Ceramics—The "Solution Ceramics" process has been licensed to the Titanium Alloy Division of National Lead Co. The "Flame Ceramics" process has been licensed to Continental Coatings Corp. A study is underway on the feasibility of coating carbon and graphite with ceramics used at high temperatures.

Air Pollution Study—An air pollutant was identified near Chicago that had been damaging auto finishes and the situation remedied.

Stainless Steel—A fundamental study of pitting corrosion in chloride solutions is under way. New alloy compositions resistant to sea water are sought.

Tin Plate—Fundamental investigation of tin plate corrosion by food is under way.

Magnesium—Electrolytic treatments of magnesium designed to improve paint adhesion are being investigated.

Hydrogen Embrittlement—The mechanism of hydrogen embrittlement is under investigation.

Titanium on Steel—A means of roll cladding titanium on steel is being probed.

Vanadium Alloys—Vanadium-base alloys for use in nuclear reactors are being surveyed and tested.

Cladding by Brazing—Titanium and zirconium have been brazed successfully to steel by the patented vacuum brazing process developed by the Chicago Bridge and Iron Company.

Rensselaer Institute Starts Corrosion Course

Rensselaer Polytechnic Institute, Troy, N. Y. effective with the spring term starts a corrosion course designed to give the student an understanding of the principles of corrosion. This is accomplished by developing a unified treatment of the fundamentals of electrochemistry, surfaces and metallurgy and an examination of corrosion types through a generalized treatment of observed phenomena.

Discussion of environmental factors follows, with testing procedures, field investigations, materials and means of protecting them in order.

Lectures For–

(Continued From Page 124)

Fundamental Field Practices Associated With Electrical Measurements, L. H. West, Standard Oil Co. (Ohio)
Electrochemical Prinicples, C. M. Rutter, Equitable Gas Co. Waxes, Ted Kennedy, Jr., Trenton Corp.
Theoretical and Fundamental Considerations for Control of Corrosion on Underground Lead Cables, K. G. Compton, Bell Telephone Laboratories.
Steel Pipe in Underground Service, W. G. Schwamb, Armco Drainage and Metal Products Co.
Electrolysis Reverse Current Switches, R. M. Keller, Atlantic Pipe Line Co.
Coatings Fundamentals, J. A. Schauers, Atlantic Pipe Line Co.
Duties of a Coatings Inspector, E. H. Snashall, Ohio Fuel Gas Co.
Coal Tar Tapes, T. B. Casey, The Tapecoat Co.
Inherent Resistance of Cast Iron Pipe to Corrosion, Thomas F. Wolfe, Cast Iron Pipe Research Association.
Plastic Pipe, Don Moritz, Plastic Pipe Div., U. S. Rubber Co.
Corrosion Control for Gas Distribution Systems, J. J. Meany, Jr., A. V. Smith Engineering Co.

Thursday, June 6

Expendable Anode Fundamentals, E. C. Reichard, Consultant, Holmdel, N. J.
Expendable Anode Application, J. M. McGinnis, Standard Magnesium Corp.
Pressure Sensitive Tapes, R. B. Bender, Plastic Engineering & Sales Corp.
Practical Aspects of a Corrosion Survey of Underground Lead Cables, J. M. Fouts, Koppers Co.
Asbestos Cement Pipe, W. S. McKay, Pipe Division, Johns-Manville Corp.
Coal Mine Corrosion Problems, E. J. Gleim, Former Chief, Branch of Electrical-Mechanical Testing, U. S. Bureau of Mines, Pittsburgh.
Tar Epoxy Coating, F. R. Charlton, Koppers Co., Inc.
Corrosion Control for Construction Personnel, W. R. Curley, Royston Laboratories, Inc.
Rectifier Units for Cathodic Protection, B. Husock, Harco Corp.
Coatings Round Table, J. A. Schauers and instructors on other classes on subject.
Practical Considerations in the Design of Corrosion Mitigation for Underground Lead Cables, J. M. Fouts.
Effect of Water Quality on the Internal Corrosion of Pipe Lines, John P. Kleber, Calgon Co.

Thursday, June 6

The following field demonstrations are scheduled:

Soil Resistivity Survey, C. C. Stoneking, Hope Natural Gas Co.
Pipe-to-Soil Potentials Survey, G. E. Gibson, Peoples Natural Gas Co.
Line Current Measurements, J. Pepper, Tuscarora Pipe Line Co., Ltd.
Magnesium Anode Installation, J. G. Keener, Manufacturers Light and Heat Co.
Cathodic Protection With Rectifier, P. G. Hoy, New York State Natural Gas Co.
Other Underground Structures, G. S. Kuech, Bell Telephone Co. of Pennsylvania.

F. E. Costanzo, Manufacturers Light and Heat Co., Pittsburgh is general chairman of the course. W. F. Fair, Jr., Tar Products Div., The Koppers Co., Inc. will make an address on the morning of the opening day.

Registration begins June 4 at 8 am at the lobby of Reynolds Hall and in the Field House. The enrollment fee of $10 covers all charges except room and board. A copy of the proceedings will be supplied each registrant.

European Federation of Corrosion Meets in May '58

The Second Congress of the European Federation of Corrosion will be held at Frankfurt am Main during the May 3-June 8, 1958 European Congress of Chemical Engineering. A 16-page brochure describing the latter meeting has been published in five languages, including English and may be obtained from Dechema, Frankfurt am Main 7, Postfach.

Atmospheric Tests of Platings Planned by ASTM

An atmospheric exposure program entailing 27 plating variations of copper, nickel and chromium plating on various aluminum alloys and steel panels has been outlined by Committee B-8 on Electrodeposited Metal Coatings of American Society for Testing Materials.

A report on the summary of tests on organic coatings used on chromium plated surfaces is expected to be published in 1957.

ASTM Meets in June

The annual meeting and exhibit of American Society for Testing Materials is scheduled for June 22-28 at Hotel Statler, Boston, Mass.

BOOK NEWS

Metallurgie—Aide-Memoire Dunod. Vol. 2, 66th Edition. (In French) 202 pages plus 64, 3¾ x 5¾ inches, cloth. By R. Cazaud. 1957. Published by Dunod, 92 Rue Bonaparte 6e, Paris, France. Per copy, Francs, 480.

Essentially a handbook for use in foundries and machine shops, Chapter 2 of the section on testing is devoted to corrosion. This section covers briefly influence of surface state, classification of tests, methods of tests, immersion, drop tests and special tests on stainless material.

Methods of measuring corrosion described include visual, weight, mechanical and tension.

A portion devoted to coatings considers metallic and non-metallic materials.

A single reference in this chapter is to an article by Evans in Revue de Metallurgie published in April, 1935.

Theories and Methods of Testing for Corrosion of Metals. By G. V. Akimov, USSR Academy of Sciences. (In French) 607 pages, 8 x 9¼ inches, cloth, 1957. Dunod, 92, Rue Bonaparte (6) Paris, France. Per copy, 5900 F.

This is a translation of the well-known Russian work by G. V. Akimov. Among other things it includes discussions on chemical corrosion and formation of protective coatings; electrochemical theories on corrosion; a study of electrode potentials, a study of the development of various kinds of corrosion, factors determining corrosion, corrosion indicators, theories concerning cathodic protection and depolarization by oxygen, experimental studies on cathodic protection of different metals.

The book, which has 388 figures, is likely to have much valuable basic information for persons sufficiently fluent in French to use the text.

Chapter 3 of this book was published in English translation in CORROSION in November and December, 1955.

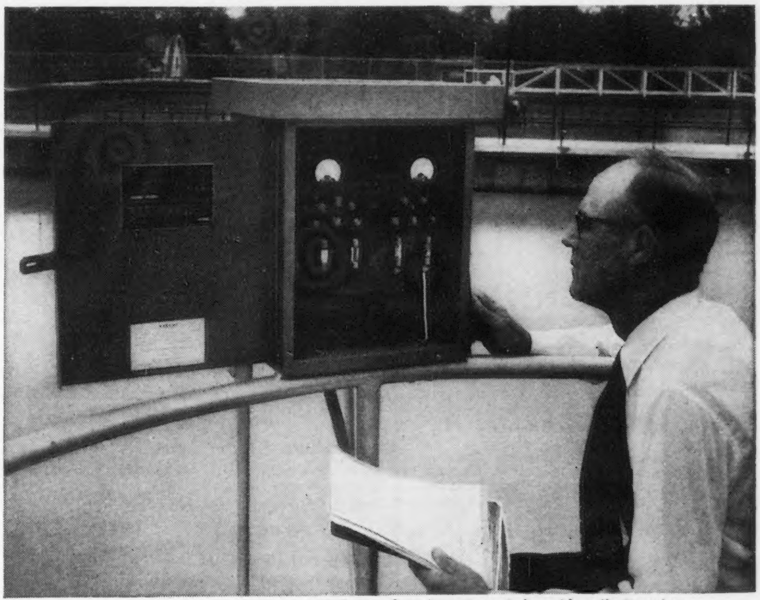
Practice of Magnetic Particle Inspection. (In French) By E. A. W. Muller, Siemens-Walske. 169 pages, 6¼ x 9½ inches, paper. 1957. Dunod, 92, Rue Bonaparte (6), Paris, France. Per copy, 1880 F.

This French translation of a German work includes five chapters as follows: 1—Principles, covering field of magnetism and its production; use of magnetic powders and sensitivity in detecting defects. 2—Examples of application and apparatus, covering the methods by which various kinds of parts are examined. 3—Demagnetization. 4—Considerations of cost. 5—Bibliography.

Unalloyed Ferritic Cast Iron Found Superior in Tests

Unalloyed ferritic nodular cast iron has proved far superior in thermal shock resistance to any gray irons tested in a research project sponsored by the American Society for Testing Materials —American Society of Metallurgical Engineers Joint Committee on the Effect of Temperature on the Properties of Metals. A progress report on the research, being conducted by J. R. Kattus, head of the Metallurgy Section, Southern Research Institute gives some of the data derived from the investigation, which began in 1954.

Creep-rupture and thermal shock tests are being made at 800 and 1000 F on seven alloys for times up to 5000 hours.



E. R. P. engineer inspects control panel for cathodic system protecting clarifiers at Louisville Water Co., Louisville, Ky.

E. R. P. CATHODIC PROTECTION

stops corrosion at lowest overall cost

Electro Rust-Proofing Cathodic Protection is used by the Louisville Water Company to prevent corrosion of metal underwater equipment in the raw water clarifiers.

Cathodic protection is the one method able to reduce corrosion of underwater metal virtually to zero. Electro Rust-Proofing Cathodic Systems are designed to provide the sole protection of submerged structures or to supplement a good protective coating. When used in conjunction with coatings, cathodic protection eliminates corrosion due to holidays or inherent breaks in coatings such as can occur at many inaccessible structural joints.

Electro Rust-Proofing designs every cathodic system individually so that maximum protection is given for the lowest operating cost. For information about E.R.P. Cathodic Protection, write for Bulletin #E-39.

ELECTRO RUST-PROOFING CORP.
A SUBSIDIARY OF WALLACE & TIERNAN INC
30 MAIN STREET, BELLEVILLE 9, NEW JERSEY

Equipment
Services

NEW PRODUCTS

Materials
Literature

Fluoroflex-T, laminated Teflon pipe manufactured by Resistoflex Corp., Roseland, N. J. is described in a new bulletin available from the company on request.

●

Castor Engineering Co., Inc. Arch St. Extension, P. O. Box 446, Carnegie, Pa. is reclaiming germanium, platinum, gold, molybdenum, nickel and copper from various types of processing scrap at a charge based on the percentage of salvage value. Two-pound samples will be evaluated by the company to determine whether or not the recovery process will show an economic advantage over other scrap disposal methods.

●

DuPont Company will build at Ecorse, Mich. on the Detroit River a modern sulfuric acid plant replacing an existing unit which has become obsolete.

●

Rectifiers for impressed current will be designed, made and marketed by Electronics International, Inc., a corporation recently organized by Wayne A. Johnson, president; Ted Riseling, vice-president and J. H. Reynolds, vice-president and secretary. The plant is located at 5310 Ashbrook St., Houston.

TECHNICAL REPORTS

on

PIPE LINE CORROSION

T-2 Statement on Minimum Requirements for Protection of Buried Pipe Lines. Prepared by a Special Task Group of NACE Technical Group Committee T-2 on Pipe Line Corrosion. Publication No. 56-15. Per Copy $.50.

TP-2 First Interim Report on Galvanic Anode Tests. (Pub. 50-2) NACE members, $3; Non-members, $5 Per Copy.

T-2B Final Report on Four Annual Anode Inspections. A Report of Technical Unit Committee T-2B on Anodes for Impressed Current. Publication 56-1. Per Copy $1.00.

T-2B Use of High Silicon Cast Iron for Anodes. First Interim Report of Unit Committee T-2B on Anodes for Impressed Current. Publication No. 57-4. Per Copy $.50.

T-2C Some Observations of Cathodic Protection Potential Criteria in Localized Pitting. A Report of T-2C on Minimum Current Requirements for Cathodic Protection. Pub. 54-2. Per Copy $.50.

T-2G Tentative Recommended Specifications and Practices for Coal Tar Coatings for Underground Use. A Report of Technical Unit Committee T-2G on Coal Tar Coatings for Underground Use. Per Copy $.50.

TP-3 First Interim Reports on Ground Anode Tests. (Pub. 50-1) NACE members, $3; Non-members, $5 Per Copy.

Remittances must accompany all orders for literature the aggregate cost of which is less than $5. Orders of value greater than $5 will be invoiced if requested. Send orders to National Association of Corrosion Engineers, 1061 M & M Bldg., Houston, Texas. Add 65c per package to the prices given above for Book Post Registry to all addresses outside the United States, Canada and Mexico.

NATIONAL ASSOCIATION OF CORROSION ENGINEERS

1061 M & M Bldg. Houston 2, Texas

●

Hyperthane, urethane coatings marketed by Kansas Paint & Color Co., 132 North Mosley, Wichita 2, Kansas are supplied as one component packages which require baking above 285 F or as two component systems which may be air-dried or baked. They may be applied by spray. brush, roller or by dipping.

●

Tufline stainless steel plug valves made by Continental Manufacturing Co., 247 Park Ave., New York 17, N. Y. have Teflon sleeves which eliminate lubrication. The valves are recommended for liquid and gaseous corrosives, solvent and slurry services and for other services where standard valves will not seat owing to mechanical interference from entrained solids.

●

Mobile Drilling, Inc., Indianapolis, Ind. has purchased the Buda Earth Drill Division of Allis-Chalmers Mfg. Co.

●

Polyvinylchloride Globe Valves, claimed to be the first with full flow passage are being made by Walworth Co., 60 East 42nd St., New York, N. Y.

●

Titanium Wire Cloth is available now on a production basis from Cambridge Wire Cloth Co., Cambridge, Md.

●

Rhodium Electroplates of at least twice the thickness formerly possible with conventional formulations now are being obtained with Sel-Rex Rhodex, a product of Sel-Rex Corp., Newark, N. J.

●

Babcock and Wilcox Company's research center at Alliance, Ohio will be increased in size by 15,700 square feet.

●

Garlock Packing Co., Palmyra, N. Y. has integrated sales forces with United States Gasket Co., Camden, N. J. which will be known as United Gasket Company, Plastics Division of The Garlock Packing Co.

●

Unitrace, Alcoa's steam-traced piping has been redesigned with a cross-section matching standard pipe sizes.

●

Carbon and synthetic graphite electrodes, anodes and other carbon and graphite products will be produced at a Lancaster, Cal. plant of Crescent Carbon Co., a subsidiary of Crescent Corporation, Tulsa.

●

Kel-F's chemical and manufacturing business has been purchased from M. W. Kellogg Co., a subsidiary of Pullman, Inc. by Minnesota Mining & Mfg. Co. The sale will not affect Kellogg's petroleum and petrochemical research laboratories and other manufacturing activities in Jersey City.

●

Magnesium-Silicide Type Aluminum Alloys are now being used to make No. 1 porcelain enameling sheet and No. 1 and 2 porcelain enamel extruded shapes. The new alloys are said by Alcoa to have uniform behavior throughout the enameling process.

●

Metallic Coatings Co. and General Sandblasting Co., 1355 West 11th St., Long Beach 13, Cal. have equipment for sandblasting large shapes and spraying and painting of exterior and interior surfaces including pipe sizes from 3-inch diameter up to 90 feet long.

●

Robertshaw-Fulton Controls Co. plans to build a $250,000 Western Research Center with 15,000 square feet of floor space.

●

Fulton-Sylphon Division, Robertshaw-Fulton Controls Co., Box 400, Knoxville 1, Tenn. is making all-metal actuators for control valves for use in corrosive conditions. They have a stainless steel bellows and stem and cadmium plated steel frame.

●

Spectrochemical Analysis, a 28-page pamphlet describing fundamentals of spectrochemical analysis is available without charge from Information Service, Jarrell-Ash Co., 26 Farwell St., Newtonville 60, Mass.

●

Silastic 960, a silicone rubber developed by Dow-Corning Corp. has tensile strength in the range of 1500 psi, tear strength approximately 200 ppi, elongation over 500 percent and hardness rating from 50 to 60 on the Shore A scale. Useful temperature range is from —130 to over 500 F.

●

Pacific Marine Supply Co., 1213 Western Ave., Seattle, Wash. has been named distributor of International Paint Co. (California) Inc., paints in the Seattle port area.

●

X-Tru-Coat, plastic coated steel pipe and tubing made by Republic Steel, 3100 East 45th St., Cleveland 27, Ohio is described in a folder available from the company. Polyethylene is hot extruded over a specially developed elastic adhesive coating on pipe. The resulting coating is tenaceous and free from holidays, the company says. Pipe so coated may be bent without affecting the coating's integrity. Field joints can be covered with pressure sensitive tape.

●

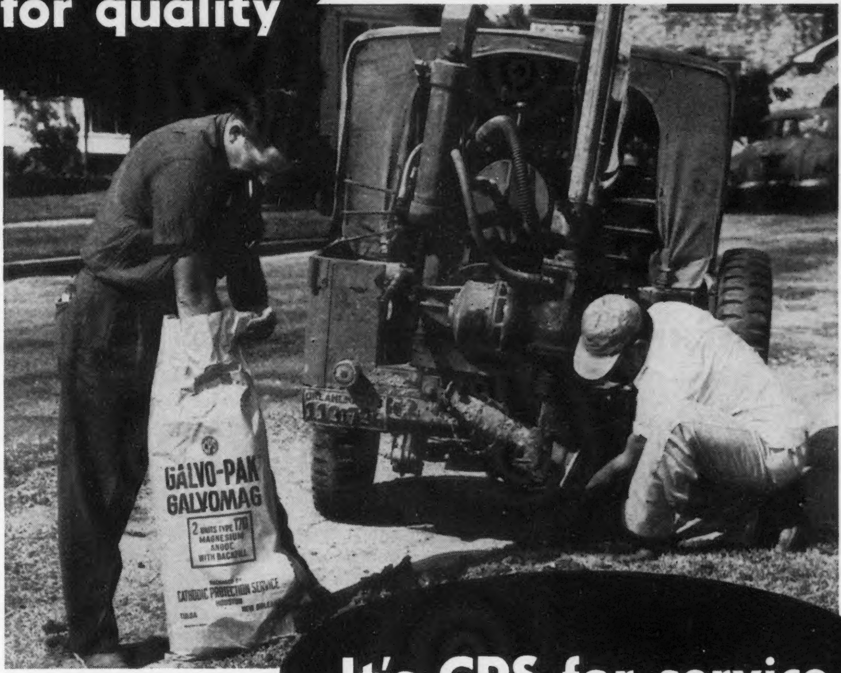
H. C. Price Co., Box 1111, Bartlesville, Okla. has developed the "Price-O-Matic Pipe-welder" which makes double-jointing automatic. The company reports x-ray and other tests have shown the quality of the welds consistently good in field tests.

●

Cathodic Protection Rectifier Equipment, a 32-page and cover brochure published by Standard Telephones and Cables, Ltd., Rectifier Div., Edinburgh Way, Harlow, Essex, England, gives a brief description of electrochemical corrosion processes and cathodic protection. The principal characteristics of the company's rectifiers are described and illustrated.

(Continued on Page 130)

It's Dow for quality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NEW PRODUCTS

(Continued From Page 128)

High Purity Vanadium and a new group of refractory metal compounds including chromium carbide, vanadium carbide, molybdenum disilicide and silicon nitride together with associated metal chemicals recently were exhibited by Electro Metallurgical Co., a Division of Union Carbide and Carbon Corp.

•

Polymerized Ethyl Silicate is being produced at Monsanto Chemical Company's Inorganic Chemicals Div. plant at Everett, Mass. The material is suitable as a binder for high temperature refractories and for application to stone or ceramic surfaces to retard weathering, among other uses.

TECHNICAL REPORTS
on
MARINE COATINGS

T-1M Suggested Coating Specifications for Hot Application of Coal Tar Enamel for Marine Environment. A Report of NACE Technical Unit Committee T-1M on Corrosion of Oil & Gas Well Producing Equipment in Offshore Installations. Publication No. 57-8. Per Copy $.50.

T-1M Suggested Painting Specifications for Marine Coatings. A Report of NACE Technical Unit Committee T-1M on Corrosion of Oil & Gas Well Producing Equipment in Offshore Installations. Publication No. 57-7. Per Copy $.50.

Remittances must accompany all orders for literature the aggregate cost of which is less than $5. Orders of value greater than $5 will be invoiced if requested. Send orders to National Association of Corrosion Engineers, 1061 M & M Bldg., Houston, Texas. Add 65c per package to the prices given above for Book Post Registry to all addresses outside the United States, Canada and Mexico.

NATIONAL ASSOCIATION OF CORROSION ENGINEERS
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•

Boilers can be supplied with preheated, non-corrosive feedwater from a new packaged feedwater unit offered by Stickle Steam Specialties Co., 2215 Valley Ave., Indianapolis 18, Ind. It is described in Bulletin 117-A.

•

Labline ultrasonic cleaners for laboratory use are now available from Labline, Inc., 3070-82 West Grand Ave., Chicago 22, Ill. The units are described in Bulletin No. 9200.

•

American Smelting and Refining Co. is expanding its central non-ferrous metal Research Laboratories at South Plainfield, N. J. by one-third. The new laboratories will be devoted to asbestos application and process research for Asarco's subsidiary, Lake Asbestos, Quebec, Ltd. and for research on refractory metals.

•

Reilly Chemical Index, 1957 Edition, available from Reilly Tar & Chemical Corp., Merchants Bank Bldg., Indianapolis 4, Ind. contains a short description of all the chemicals made by the company. It includes eight new compounds developed during 1956.

•

Kaiser Aluminum & Chemical Corp. is enlarging by 21,600 square feet its Wanatah, Indiana aluminum food container plant.

•

Pliohard, a synthetic rubber enamel to protect the finish on hydraulically operated equipment is available from Saran Protective Coatings Co., 2415 Burdette Ave., Ferndale 20, Mich. The material, made from styrene butadiene resins, air dries dust free in 30 minutes on metal and non-metallic surfaces. It is a thermoplastic and is non-oxidizing with an upper temperature limit of 250 F.

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DuPont has started construction on a fifth laboratory building at the Chestnut Run center for sales services research near Wilmington. It will conduct customer service and development work on titanium, silicon, pigments, sodium, peroxygen, chlorine, vinyl and related product fields. Its cost will be about $5 million.

•

Associated Spring Corp., Bristol, Conn. is establishing a new research center at its Bristol headquarters, more than doubling facilities and staff. H. Perry Smith, formerly manager of the general research laboratory of Underwood Corp., Hartford, Conn. will be in charge of the new center as assistant director of research.

•

Carpenter Steel Co., 372 West Bern St., Reading, Pa. has published a 20-page booklet giving the engineering properties and fabrication characteristics of ten high-strength alloys for high temperature service.

•

Neptune Meter Co., 19 West 50th St., New York 20, N. Y. has developed a meter made of Type 316 stainless steel with only one moving part exposed to liquid. It measures the liquids inside the pipe.

•

Allegheny Ludlum Steel Corp. will centralize research facilities at a Brackenridge, Pa. site when three more buildings, two laboratory buildings and an administration building, have been completed. Two buildings already are on the site.

•

Alloy Surfaces Co., 103 South Justison St., Wilmington 1, Del. has developed a method of diffusion coating ordinary steels with 430 stainless steel. The process is adaptable to finished and unfinished products and produces a coating which is integral with the basis metal. Surface hardness up to RC 70-72 also can be given medium and high carbon steels.

MEN in the NEWS

Fred Koelble is a staff assistant for Pennsalt Chemicals' Corrosion Engineering Products Department.

•

Carl E. Schmitz has been named executive vice president of Crane Packing Company. He is a NACE member.

•

F. A. Lowenheim has been appointed technical advisor to the vice president of Research and Development of Metal & Thermit Corp., Rahway, N. J. **R. W. Couch** has been made manager of Electrochemical Research and **Carl R. Gloskey** has been appointed manager of the company's recently formed Process Development Division.

•

John H. Chase, a member of NACE died at his home in LaJolla, Cal. February 7.

•

E. H. Sangwine has been made manager of Kaiser Aluminum & Chemical Corp. $70 million alumina and caustic chlorine facilities now under construction near Gramercy, La. on the Mississippi River.

•

Charles F. Bradley, for 30 years director of publicity for Oakite Products, Inc.,

(Continued on Page 131)

MEN in the NEWS

(Continued From Page 130)

has retired from active duty with the company.

●

John J. Constantino has joined the chemical department of Water Service Laboratories, Inc., 423 West 126th St., New York, N. Y.

●

Robert C. Anderson has opened consulting metallurgical engineering offices at 7738 Park Place Blvd., Houston.

●

Max Swerdlow, research physicist with the National Bureau of Standards has been chosen president elect of the Electron Microscope Society of America, an affiliate of the American Association for the Advancement of Science and of the American Institute of Physics.

●

Blanton C. Duncan has rejoined the surface chemistry section of the National Bureau of Standards.

●

A. J. Williamson has been elected president of Tube Reducing Corp., Wallington, N. J.

●

Richard P. Simmons has been appointed manager of processing of the Toronto, Ohio plant of Titanium Metals Corp. of America, now being rebuilt as a specialized facility for forging alloy titanium billets and rolling and heat treating large-size, high strength alloy titanium sheet.

●

Robert C. Booth, formerly a representative of Plastic Applicators, Inc. in the Houston area has been made general manager of the firm's new Odessa, Texas plant.

●

John C. Wallace has been named vice-president of engineering for the Walworth Company.

●

John A. Howsom, formerly leader of the physical chemistry section, American Viscose Corp. has been made manager of basic research.

●

G. O. Hoglund, head, joining section, Aluminum Company of America's process development laboratories has been elected first vice-president of the American Welding Society, Inc.

●

Edward Teller, a pioneer in theoretical physics and an authority on atomic energy has received the 1957 Dickinson College Priestly Memorial Award and a cash grant from the National Cylinder Gas Co. He is associate director of the radiation laboratory at the University of California at Berkeley, a professor of physics at the university and a member of the general advisory committee of the Atomic Energy Commission.

●

John Kempf has joined the technical staff of Furane Plastics, Inc., 4516 Brazil St., Los Angeles 39, Cal. as product development manager of adhesives and coatings.

●

Marcel A. Cordovici, head of the materials and testing department of The Babcock & Wilcox Company's Atomic Energy Division has been named recipient of the second annual Industrial Achievement Award of the New York Chapter of the American Society for Metals.

●

Peter Hidnert, an expert in the field of thermal expansion retired March 31 after 45 years at the National Bureau of Standards.

●

Charles W. Bird, Jr. has been elected president of The Bird-Archer Co., water treatment engineers. He succeeds **H. C. Harragin,** retired, who will continue as president of Bird-Archer Co., Ltd. of Canada.

●

Ardon B. Judd has been elected president of Southwest Fabricating & Welding Co., Houston, a subsidiary of the Walworth Company.

●

Clarence P. Sander, general superintendent, Vernon Plant, Consolidated Western Steel Div., United States Steel Corp. has been elected president of the American Welding Society.

●

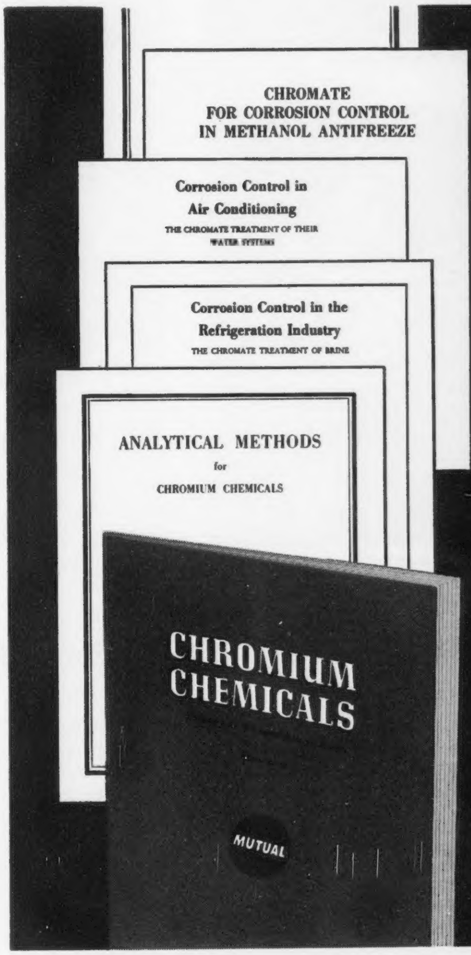
H. T. McBride, superintendent of maintenance for the Chemical Group, Pittsburgh Coke & Chemical Co. has been elected president of the Pittsburgh chapter, American Institute of Plant Engineers.

●

Howard F. Park, Jr., vice-president, General Steel Castings Corp., Granite City, Ill. has been reelected president of Steel Founders' Society of America.

●

Organizations of corrosion engineers have been founded in England, France, Germany, Italy, Australia and Japan since NACE was established.


CHROMATE FOR CORROSION CONTROL IN METHANOL ANTIFREEZE
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No. 51—Analytical Methods for Chromium
No. 52—Chromium Chemicals, History—Properties—Uses
No. 53—Corrosion Inhibitors in Recirculating Water Systems
No. 55—Corrosion Inhibition with Chromate (in the Oil and Gas Industries)
No. 93—Chromate for Corrosion Control in Methanol Antifreeze
No. 144—Chromate Treatment for Preserving Exterior Brightness of Processed Food Containers
No. 153—Inhibiting Corrosion of Steel, Aluminum, and Magnesium Intermittently Exposed to Brines

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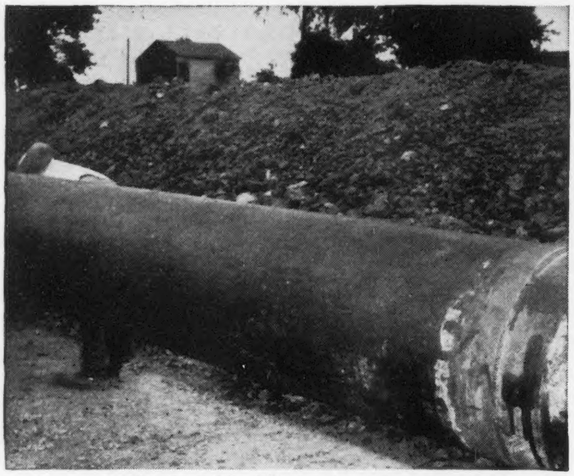

Pipe, buried for 25 years, is good as new

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THIS PIPE IS 25 YEARS YOUNG

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Coats more feet per man-hours because less material is needed • Applied hot or cold • By hand, by Traveliner or at the mill • Requires less equipment • No noxious fumes.

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Company..
Address...
City.................................*Zone*....*State*...........

CORROSION ABSTRACTS

INDEX TO CORROSION ABSTRACTS

Vol. 13 May, 1957 No. 5

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3. CHARACTERISTIC CORROSION PHENOMENA

3.7 Metallurgical Effects

3.7.3, 6.3.6, 7.4.2

Welding Copper Alloys: Fabrication of Heat-Exchanger Components for the Oil Industry. Imperial Chemical Industries Ltd. *Metal Ind.*, **88**, No. 17, 353-357 (1956) April 27.

At this symposium, organized by ICI Metals Division, papers included: Seal-Welding Heat-Exchanger Tube Ends, L. J. P. Smulders; Condensers Cooled by Sea Water, E. D. Dolan; Floating Head Covers—the Alternatives, H. R. Meeker; Copper Alloys for Heat-Exchanger Construction, W. H. L. Hooper; Which Welding System to Choose, D. C. Moore.—BNF. 12115

3.7.4

Diffusion Short Circuits in Metals. R. E. Hoffman. *Gen. Elec. Rev.*, **59**, No. 2, 28-31 (1956) March.

Explains migration of atoms across grain boundaries as being analogous to electron flow in a conductor and illustrates diffusion, grain boundary orientation and dislocations with reference to raft of soap bubbles. Changes in grain size and effects on final properties of an alloy caused by grain-boundary diffusion are considered. Photomicrograph, radiograph, illustrations.—INCO. 12039

3.8 Miscellaneous Principles

3.8.2

Acceleration of the Dissolution of Iron in Sulfuric Acid by Ferric Ions. Harry C. Gatos. *J. Electrochem. Soc.*, **103**, No. 5, 286-291 (1956) May.

The dissolution of iron in sulfuric acid solutions was studied as a function of Fe^{3+} concentration. In 1N sulfuric acid the dissolution rate (5-hr. period) increased at first with Fe^{3+} concentration and then decreased beyond 0.47 Fe^{3+} g ion/l until at 4.00 Fe^{3+} g ions/l, it became approximately equal to the rate in 1N sulfuric acid containing no Fe^{3+}. The hydrogen evolution rate decreased with time and with Fe^{3+} concentration. For a given Fe^{3+} concentration, the dissolution rate decreased and the hydrogen evolution rate increased with increasing H^+ concentration.

The accelerating effect of Fe^{3+} is due to the direct reduction of the Fe^{3+} to Fe^{2+}. Consumption of Fe^{3+} was related to iron dissolution according to Faraday's law. Decrease in hydrogen evolved was considered the result of unfavorable electrode conditions for the reduction of H^+, created by the reduction of Fe^{3+} to Fe^{2+}. 12015

3.8.2

Kinetics of the Corrosion Process. A. I. Shultin. *J. Applied Chem., USSR* (Zhurnal Prikladnoi Khimii), **29**, No. 2, 369-379 (1956) Feb.

A theoretical analysis of electrochemical oxidation-reduction of metals. 5 figures, 6 references.—ATS. Translation available: Associated Technical Services, P. O. Box 271, East Orange, New Jersey. 12138

3.8.2

The Kinetic Significance of the Individual Stages of the Corrosion Process. A. I. Shultin. *J. Applied Chem., USSR* (Zhurnal Prikladnoi Khimii), **29**, No. 2, 217-229 (1956) Feb.

The effect of various factors on the rate of corrosion of metals and alloys in solutions of electrolytes was evaluated. 3 figures, 13 references.—ATS. Translation available: Associated Technical Services, P. O. Box 271, East Orange, New Jersey. 12140

3.8.2

Corrosion and Electrochemistry. (In German.) G. Valensi. *Z. Metallkunde*, **47**, No. 1, 50-52 (1956) Jan.

A discussion on the terminology of chemical and electrochemical corrosion. 18 references. This subject is being considered by a group of the Comite International de Thermodynamique et de Cinetique Electrochimique.—BNF. 12142

3.8.2

Use of the Oscillographic Method for the Study of the Kinetics of the Solution of Iron in Sulfuric Acid. (In Russian.) Ia. V. Durdin and V. I. Kravtsov. Vestnik Leningradskogo Universiteta, Seriia Matematiki. *Fiziki i Khimii*, **11**, No. 4, 127-131 (1956) Feb.

Oscillograms of the switching on and off of direct current were photographed. Equations relate the variation in potential and cathodic polarization. Graphs, table. 6 references.—BTR. 11988

3.8.2

Study of Corrosion Properties of Metals. I. Oknin. *J. Applied Chem., USSR* (Zhurnal Prikladnoi Khimii), **29**, No. 3, 360-369 (1956) Feb.

A theoretical discussion. 2 figures, 9 references.—ATS. Translation available: Associated Technical Services, P. O. Box 271, East Orange, New Jersey. 12080

3.8.2, 3.8.4

Chemical and Electrochemical Corrosion. (In German.) Heribert Grubitsch. *Z. Metallkunde*, **47**, No. 3, 184-190 (1956) March.

Definitions of electrochemical and chemical corrosion phenomena. The primary stage of corrosion consists in an adsorption of ions or molecules; it was found that adsorption according to van der Waals does not contradict the electrochemical corrosion theory. Graphs, micrographs, diagram. 104 references.—BTR. 12010

3.8.4, 6.3.19

First Stages of Oxidation of the Zinc (0001) Surface. (In Italian.) G. P. Bolognesi. *Metallurgia Italiana*, **48**, No. 3, 119-123 (1956) March.

The atmospheric corrosion of zinc single crystals was studied by measuring the angle of contact of a drop of water placed on the surface, by determining the volume of hydrogen it could release and by measurements of potential.—BNF. 11972

4. CORROSIVE ENVIRONMENTS

4.3 Chemicals, Inorganic

4.3.2, 7.6.5

Corrosion in a Nitric Acid Concentrator. Fred H. Meyer, Jr. National Lead Co. of Ohio. U. S. Atomic Energy Comm. Pubn., AECD-3735 (no date), Declassified January 9, 1956, 11 pp. Available from: Office of Technical Services, Washington, D. C.

Corrosion rates of stainless steels and other construction materials in nitric acid concentrator process solutions under operating conditions were determined. Stainless steel No. 347 showed lower corrosion rates in boiling nitric acid-hydrofluoric acid solutions under reduced pressures.—NSA. 12094

4.3.2, 8.8.1

Propylene Polymerization in Packed Reactor—Liquid Phosphoric Acid Catalyst. S. R. Bethea and J. H. Karchmer. Paper before Am. Chem. Soc., 127th Ann. Mtg., Petroleum Chem. Div., Cincinnati, March-April, 1955. *Ind. & Eng. Chem.*, **48**, No. 3, 370-377 (1956) March.

Describes process and pilot plant equipment for catalytic polymerization of propylene-containing gases to C_9 to C_{12} olefin polymers. Preheater is Type 304; vaporized feed flow line, reactor and water-cooled condenser are of Hastelloy B; acid settler is stainless steel; and acid preheater is Hastelloy B. Reactor was packed with copper pellets. Preliminary work showed that corrosion rate of Types 304 and 316 could be reduced to below 0.03-inch per year at 360 F by addition of 0.5 arsenic trioxide to phosphoric acid catalyst. Static tests were conducted to evaluate corrosion resistance of copper in catalyst. Under static conditions, corrosion rate of copper is independent of catalyst strength in range of 98-109% phosphoric acid and averages 0.016-inch per year. Corrosion rates increased to 0.05 and 0.2-inch per year when catalyst flowed across surface at rates of 4 and 16 ft. per minute, respectively. Copper reactor lines could be used to control corrosion only if air is excluded and if surface of copper is protected by acid-resistant material to prevent erosion by flowing acid. Tables, graphs, 25 references.—INCO. 11977

4.3.5, 3.2.2

Materials of Construction for Hydrogen. B. B. Morton. *Petroleum Refiner,* **35,** No. 3, 164-166 (1956) March.

Discusses the three unfavorable effects of hydrogen on steel—decarburization, blistering and cracking—and prevention of these effects through use of proper alloys and steels in hydrogen producing units and equipment exposed to hydrogen in service. Among materials considered are Type 310, 35 nickel-20 chromium steels and 79 nickel-15 chromium heat resisting alloy.—INCO. 12074

4.3.5, 3.4.6

Effect of Air on the Corrosion of Metals by Chlorine at High Temperatures. Kh. L. Tseitlin. *J. Applied Chem., USSR* (Zhurnal Prikladnoi Khimii), **29,** No. 2, 229-236 (1956) February.

Maximum temperatures of satisfactory resistance to corrosion of various ferrous and nonferrous metals and alloys are given. 1 table, 1 figure, 15 references. —ATS. Translation available: Associated Technical Services, P. O. Box 271, East Orange, New Jersey. 12136

CASING IN 62 OIL WELLS PROTECTED FROM CORROSION

Here's how an oil producing company on the Gulf Coast stopped external casing corrosion on 62 of its wells. Five of the wells were in a salt water bay.

Potential-drop profiles indicated that cathodic protection could be applied to the total depth of 5,500 feet. CSI determined the current requirements, using the log current-potential method.

Then CSI engineers designed and installed a protective system for each well based on a guaranteed current output. The range of current requirements was from 0.5 to 6.2 amperes. The necessary current was delivered from ground beds each containing from two to 16 magnesium anodes. Galvomags, Dow's new high potential anodes, were used in special lengths to provide 10-year installation life at the lowest possible cost. This cost ranged from $215 to $510 per well.

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CSI

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4.4 Chemicals, Organic

4.4.3, 4.4.8, 5.8.4

Corrosion of Metals by the Aqueous Solutions of Non-Ionic Surface-Active Detergents. Y. Kato and S. Sato. *J. Chem. Soc. Japan,* Ind. Chem. Sect., 59, 503-505 (1956) May.

The action of dilute aqueous solutions of non-ionic surface-active agents on mild steel, zinc, aluminum and tin was studied. Three types of polyethyleneoxide derivatives (laurylalcohol, nonylphenol and laurylamine) were used.

The change of weight and surface appearance of metal specimens were observed after immersion for 70 hours at 40 C in the solutions; and when corrosion occurred, its prevention using water-soluble rust-preventive substances was tried.

Results are as follows: Mild steel: Corrosion occurred in all cases, though the increase of concentration of surface-active agent, especially with more than 1% solution of laurylamine, decreased corrosion. Zinc: Weight loss had a tendency to decrease with the increase of concentration of laurylalcohol and nonylphenol; but when laurylamine was used, increased somewhat. Aluminum: Aluminum was attacked by the solution of laurylamine and the increase of concentration resulted in increase of weight, but the solution of laurylalcohol and nonylphenol produced no attack and consequently prevented corrosive action of water. Tin: Tin was not attacked by water and non-ionic surface-active agents used in this study.

Though corrosion occurred by these aqueous solutions, in the case of mild steel, the addition of 0.1% of sodium nitrite, potassium chromate, sodium phosphate or sodium benzoate prevented corrosive action of these solutions; in the case of zinc or aluminum, the use of 0.1% of zinc chromate also prevented corrosive action of these solutions.—JSPS. 12119

4.4.3, 4.6.4, 5.8.2

Recent Investigations and Experiences on Corrosive Properties of Cooling and Anti-Freezing Media for Use in Automobiles. (In German.) A. Bukowiecki. *Schweiz. Arch. angew. Wiss. u. Tech.,* **22,** No. 3, 65-74 (1956) March.

Investigations of corrosive effects and their reduction by inhibitors. Metals tested included steel, copper, 50/50 tin/lead solder, Avional (aluminum-4.5 copper-0.6 magnesium), low-alloy cast iron (0.6% chromium, 0.6% molybdenum) and Silufont-2 (aluminum, 11-13.5% silicon), against water and ethylene glycol. 18 references.—BNF. 11952

4.4.7, 7.1, 2.3.9

Investigation of the Wear Properties of Oils and Fuels with the Aid of Radioactive Isotopes. (In Russian.) Yu. S. Zaslavskii. Paper in Meetings of the Division of Technical Sciences. (Session of the Academy of Sciences of the USSR on the Peaceful Use of Atomic Energy, July 1-5, 1955), 115-139. Moscow, Publishing House of the Academy of Sciences of the USSR, 1955, 339 pp.

A high-speed investigation of the anti-wear properties of lubricating oils is achieved by tests made in one-cylinder engines with the upper pressure piston ring subjected to bombardment with neutrons on F^{59} or containing admixtures of Zn^{65}. The radioactivity of the oil is measured when the engine is running either by taking samples in a test tube inserted in a block of six gamma Geiger counters placed in a lead chamber, or by connecting a block of counters in the oil line of the engine. Measurement of the radioactivity of the standard solution of a batch of the irradiated metal is carried out in a vessel, the form of which is the same as that in the lubricating line in which the radioactivity of the oil in the engine is being measured. Because of similar measurement geometry it becomes possible to reduce the radiometric wear data of the radioactive part to weight indices. This method makes it possible to eliminate preliminary calibration of the lubricating line proposed by scientists abroad. An investigation was made of the influence of revolutions and loads on the wear of a one-cylinder four-stroke carburetor engine running on different-quality oils at high and low temperatures of the cooling water. It was established that the engine wear increase with an increase in the revolutions and loads and the difference in the anti-wear properties of the oils becomes clearer. In studying the corrosion of ferrous and non-ferrous metals and allows under the action of lubricating oils, use was made of radioactive metal plates periodically immersed in test tubes containing the oils being tested; the temperature of the oils was thermostated at a given level. The corrosion dynamics of steel and cast iron was established in motor oils with and without additives. Temperature curve maximums have been found for cast-iron and steel corrosion under the action of motor oils. The introduction of radio-sulfur S^{35} and radiophosphorous P^{32} into anti-corrosion additives to motor oils has made it possible to study the kinetics of the formation of protection films on the surface of various metals and alloys. An investigation has been made of the character of the temperature curves of film-formation by sulfur- and phosphorus-containig additives on various metals. (auth).—NSA. 11937

4.6 Water and Steam

4.6.13

Sour-Water Stripping Unit. F. L. Resen. *Oil Gas J.*, **54**, No. 45, 138, 141, 143 (1956) March 12.

Describes stripping facilities at Shell Oil's Houston refinery to treat sour water accumulated from various processing units. Process consists of injecting sulfuric acid to decompose potassium and other stable sulfides, releasing hydrogen sulfide and equivalent sulfides. Acid is pumped through carbon steel piping and is injected through Hastelloy nozzle with a Teflon tip. Plain Hastelloy tip was subject to corrosion where acid met sour-water stream, and required frequent replacement. To avoid corrosion

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downstream of injection point, plastic-coated pipe is used. Corrosion problem in columns containing Turborigid trays was combatted by coating column and trays with epoxy-resin-based paint.—INCO. 12087

4.6.2, 5.8.2

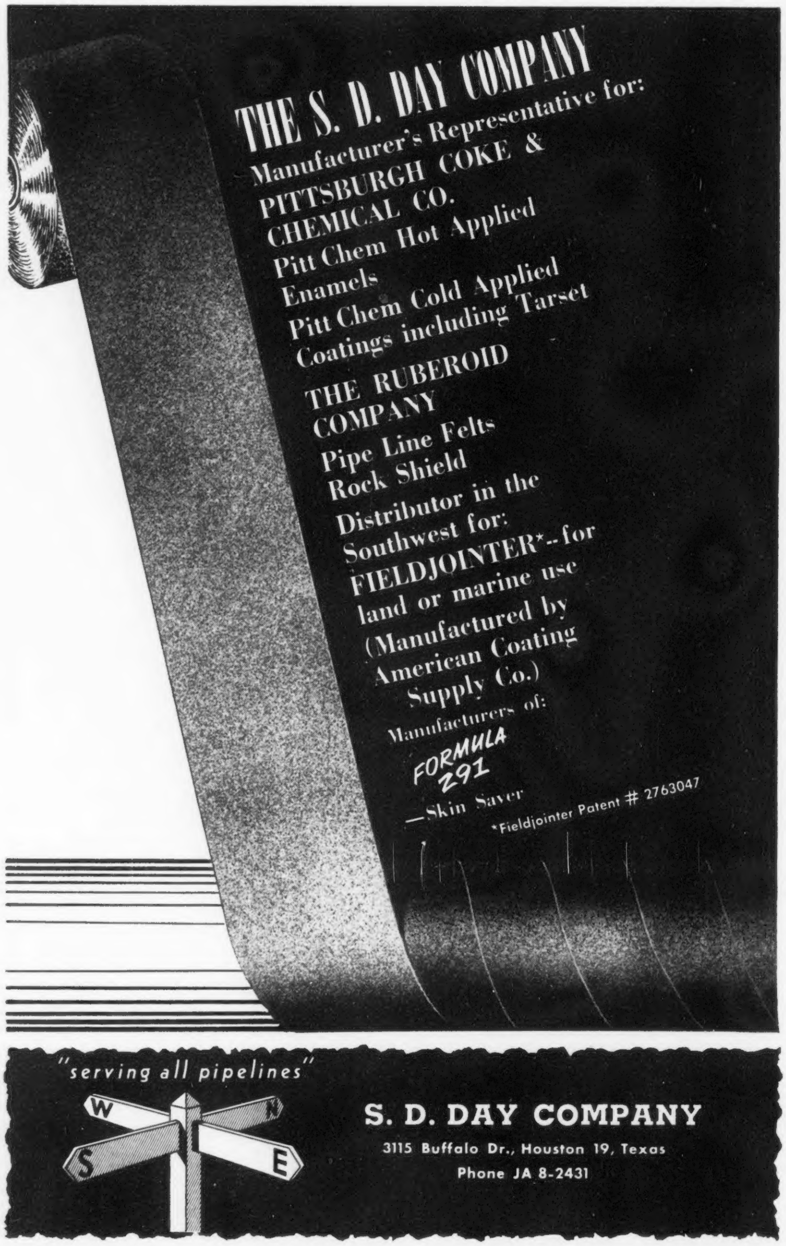
Improvement in Heat Transfer with Use of Filming Amines. J. R. Coursault. W. H. & L. D. Betz. Tappi, **39**, No. 4, 146A-149A (1956) April.

Filming amines serve a dual function in paper mills by minimizing corrosion in condensate systems and improving the efficiency of heat transfer. Corrosion in condensate systems is due to the oxygen and carbon dioxide content in the boiler make-up water. Use of a de-aerating heater will rid the feed water of free carbon dioxide. Corrosion due to the acidic nature of carbon dioxide dissolved in the water can be offset by inhibitors but these are not satisfactory since they are difficult to control and react to any copper or copper alloy in the system. Filming amines function by laying down a thin film on the metal surfaces contacted and since the water being carried will not wet the metal surfaces, excellent protection is afforded. Photos.—INCO. 11983

4.6.4, 5.8.2

Corrosion and Deposit Control in Cooling Water Systems. C. H. Cook. Cyrus Wm. Rice & Co. *Combustion*, **27**, No. 3, 53-56 (1956) March.

Explains origin of corrosion and deposition problems encountered in cooling water systems and describes common methods of treatment. Langelier Index control or control of pH is used to limit deposition of calcium carbonate to thin protective film on metal surfaces. Algae and organic slime control is accomplished by chlorination and addition of algaecides. Corrosion inhibitors discussed include chromates, polyphosphates, chromate-polyphosphates, silicates, silicate-polyphosphates, polyphosphate-cyanide and chromate-phosphate-zinc. Treatment calculations are shown.—INCO. 11961



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5. PREVENTIVE MEASURES

5.2 Cathodic Protection

5.2.1

A Critical Look at Cathodic Protection. G. Corfield. *Gas*, **32**, No. 5, 11 (1956) May.

Discussion of cathodic protection in controlling corrosion of buried pipelines. Circumstances submitted under which cathodic protection as normally applied and maintained may not prevent corrosion include loose and sagging pipe coating, numerous and active bacteria and high soil resistance. Questions posed to stimulate research include whether the voltage across the pipe coating, earth to pipe, deteriorates the coating and if so what value should normally not be exceeded and the possibiilty that the release of nascent or atomic hydrogen at the pipe surface by the cathodic protective current causes deterioration of the pipe.—INCO. 11957

5.2.1

Electrical Corrosion Protection of Buried Cables and Pipes. (In German.) Heinrich Riedel. *Elektrotech. Z., Ser. A*, **77**, No. 5, 129-136 (1956) March.

Apparatus and devices used in cathodic protection process. Graphs, diagrams, 22 references.—BTR. 12088

5.2.1, 1.7.3

Cooperation Helps Control Corrosion. C. L. Mercer. *Pipe Line Industry*, **4**, 27-28 (1956) March.

By voluntarily working together in a control committee, cathodic protection is made more effective for all operators of buried pipe lines and telephone cables. Diagrams.—BTR. 12090

5.2.1, 1.7.3, 8.9.3

Cathodic Protection: A Cooperative Endeavor. H. L. Hamilton. A. V. Smith Eng. Co. *Gas Age*, **117**, No. 9, 40-50 (1956) May 3.

Discussion of the need for cooperation in the establishment of effective corrosion protection of underground pipe lines. Basic corrosion engineering is discussed as to construction design, grid and interference problems. Careful field procedures and sound design together with thorough study of the problem by trained engineers and notification of neighbors of protection scheme before installation so that interference tests may be conducted are recommended procedures for minimizing the engineering expense to everyone involved. Case histories and technical discussions of four pipelines are given. Illustrations.—INCO. 12003

5.2.1, 4.5.3, 1.6, 2.3.7

Contributions of J. M. Pearson to Mitigation of Underground Corrosion. NACE Pubn. No. 56-12, 1956, 56 pp. Available from: National Association of Corrosion Engineers, 1061 M & M Building, Houston 2, Texas.

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son, an acknowledged expert on underground corrosion mitigation and one paper by a co-worker, prepared under his leadership, are reprinted. The six papers, reprinted by permission from the *Petroleum Engineer* and *Transactions of The Electrochemical Society* where they were published originally in 1941-44, cover electrical examination of coatings, "null" methods, determination of current required, concepts and methods of cathodic protection and preventive maintenance by inspection. The newcomer and longtime worker on underground corrosion problems alike will find these papers include useful information. 12097

5.2.1, 4.6.1

Cathodic Protection Teams Up With Water Treatment to Stop Corrosion. M. J. OLIVE. Arkansas Fuel Oil Corp. *Petroleum Refiner,* **35,** No. 4, 188-191 (1956) April; *Oil Gas J.,* **54,** No. 50, 220-227 (1956) April 16.

In water systems containing large amounts of minerals and corrosion products, cathodic protection gives good corrosion protection and scale prevention in locations where water treatment is not sufficient. Magnesium anodes offer the best solution since they are inexpensive and can be obtained in small and specific shapes. Restriction of anode output is best achieved by coating the anodes with polyvinyl chloride and sizing the output holes. A current density of better than 1 ma/sq. ft. is needed in most systems. The most economical approach to corrosion and scale control is anodes in conjunction with a good water treatment. Photos.—INCO. 12101

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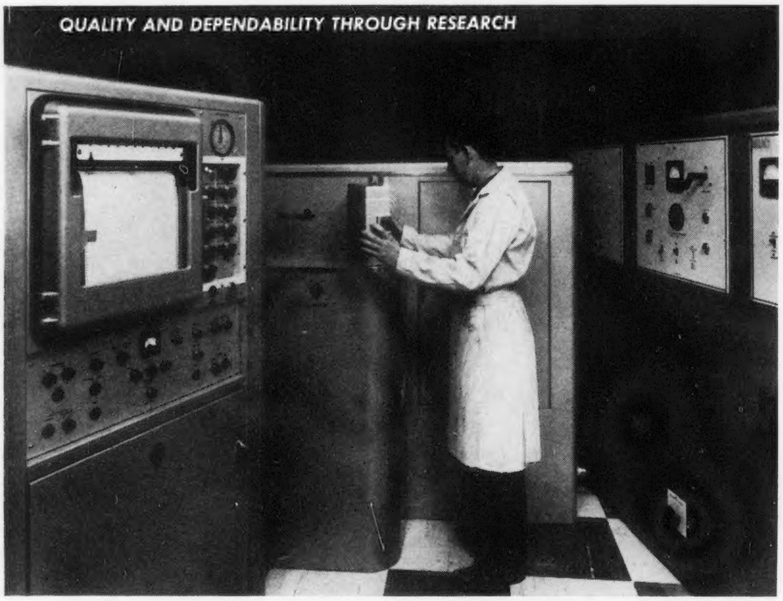

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5.2.1, 7.5.5

Save Tanks with Cathodic Protection. W. A. JOHNSON. Corrosion Rectifying Co. *Petroleum Refiner,* **35,** No. 3, 216-217 (1956) March.

Discusses rectifying system and galvanic anode systems of cathodic protection as applicable to underground pipes and tanks and to bottom of tanks resting on ground. Survey of facilities to indicate best method of protection and cost of installation is considered.—INCO. 12012

5.2.1, 8.9.3, 1.2.2

Economics of Cathodic Protection for Distribution Piping. J. S. DORSEY, S. K. GALLEY AND R. H. KERR. Paper before Pacific Coast Gas Assn., Tech. Services Mtg., Feb., 1956. *Gas Age,* **117,** No. 8, 34-38, 66-68 (1956) April 19.

Description of a few of the physical problems characteristic of cathodic protection as applied to a gas distribution system. A general discussion of engineering economics and appropriate economic considerations applied to the cathodic protection problem and specific data from the experience of a company are given. Discussion of the factors which should be evaluated with particular caution in basing cathodic protection policy decision upon the results of economic analysis is given.—INCO. 11973

5.2.1, 8.9.4

Voltmeter Protective Device. E. C. PAVER. Northern Illinois Gas Co. *Gas Age,* **117,** No. 8, 19-21 (1956) April 19.

Description of specially designed device for electric railways that cuts down high reversal voltages and permits extremely accurate readings down to 0.1 volt. It enables selection of proper location, proper and most economic type of drainage ties and equipment and efficient cathodic protection. Diagrams.—INCO. 12103

5.3 Metallic Coatings

5.3.2, 2.2.2

Sprayed Aluminum Coatings. U. R. EVANS. *Chemistry & Industry,* No. 12, 195-196 (1956) March 24.

Statement on cathodic protection of bare steel by sprayed aluminum. In 1931, steel plates sprayed with aluminum were exposed to atmosphere unfavorable to cathodic protection. Scratch lines were traced through coatings and typical rust developed. Brown rust gradually disappeared and after 3 months, dark stain developed. After 7 years, steel exposed at gaps was uncorroded and rust-free, clearly indicating cathodic protection. Breaking-down of oxide film on aluminum and plugging of pores with oxide and precipitation of hydroxide in aluminum and zinc coatings are discussed.—INCO. 12022

5.3.2, 3.5.8

Internal Stress in Electrodeposits. (In German.) H. FISCHER, P. HUHSE AND F. PAWLEK. *Z. Metallkunde,* **47,** No. 1, 43-49 (1956) Jan.

Internal stress in copper electrodeposits and its dependence on organic additions to the bath were measured mechanically (using the "Kontractometer" [*Z. Elektrochem.,* **24,** 300 (1918); **33,** 290 (1927)] and magnetically (with copper deposited on Permalloy, iron-67% nickel). X-ray, micrographic and microhardness examination showed that stresses depend not on the thickness but on the structure of the deposit. Relation of stress to structure and hardness.—BNF. 12021

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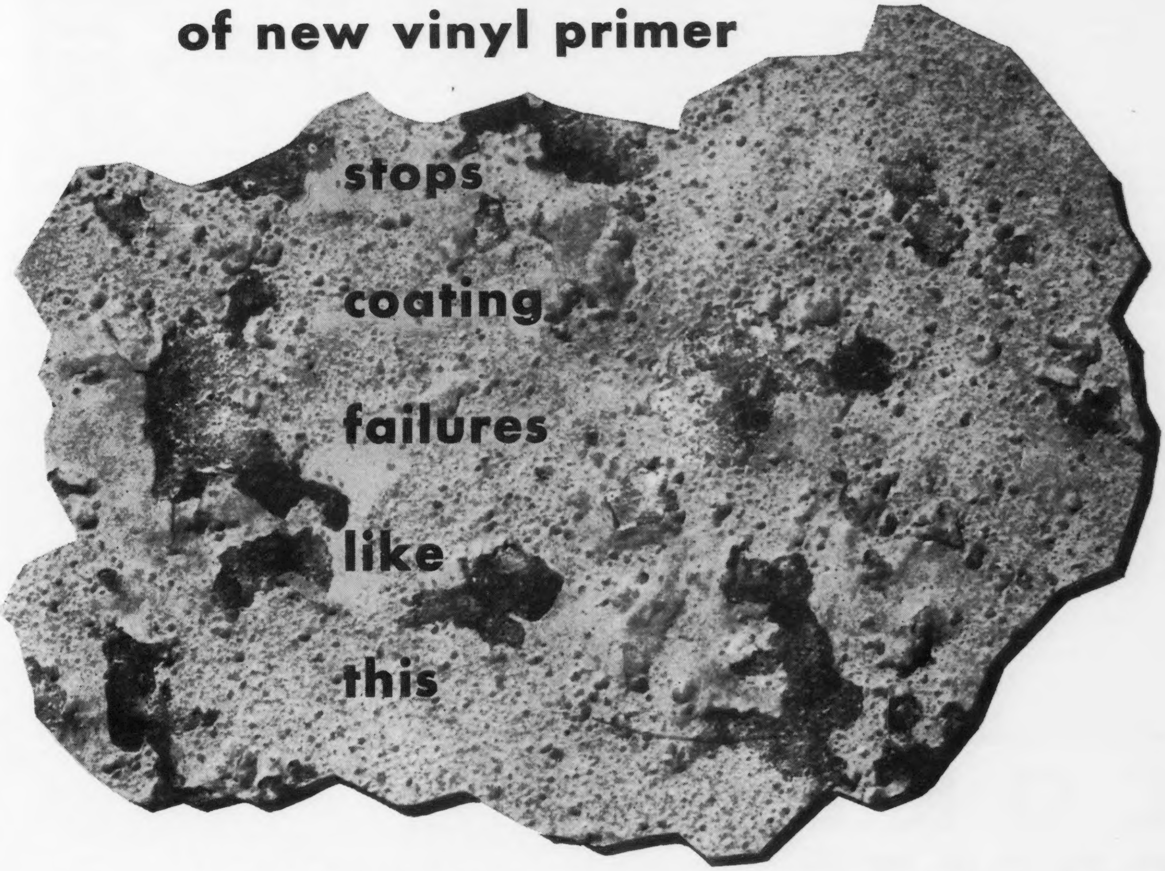

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5.3.2, 3.5.8, 2.3.7

Stress in Electrodeposited Coatings: Its Significance and Measurement. J. B. Kushner. *Metal Finishing,* **54,** Nos. 4, 5, 48-51, 57; 58-63 (1956) April, May.

Considers in detail the significance of stress and its influence on plate adhesion, cracking of deposits, blistering, distortion of thin metal sections, stress-corrosion and fatigue strength loss. Temperature, current density, agitation, bath composition (nickel content, pH, anions, metallic impurities, addition agents) and deposit thickness are discussed as plating variables that influence stress. To explain origin of stress in electroplated coatings, excess energy theory, hydrogen or hydride theory and hydrate or basic oxide theory are discussed. Various methods for quantitative measurement of stress are described. All references are made to nickel plating. Graphs, diagrams.—INCO. 12075

5.3.2, 3.7.3, 3.5.9

The Development of Zirconium-Rich Protective Coatings and Brazing Materials for Heat-Resisting Alloys. A. Blainey. Paper before ASTM, 58th Ann. Mtg., Symp. on Metallic Materials for Service Above 1600°F., Atlantic City, June 30, 1955. ASTM Spec. Tech. Pubn. No. 174, 1956, 183-193. Available from: Am. Soc. Testing Matls., 1916 Race St., Philadelphia 3, Pennsylvania.

Present investigations demonstrate-feasibility of producing hard protective coatings of zirconium-rich alloys on surface of nickel-base alloys and heat resistant steels to prevent erosion of hot compacting and extrusion dies. Coating with zirconium or zirconium alloy powder is described and results of investigating process variables, erosion by uranium and magnesium-magnesium oxide cermets, hardness and heat treatment and high temperature oxidation are discussed. Hardness is increased by proper alloying additions (tungsten, molybdenum, chromium, aluminum, lead) and heat treatment. Resistance to oxidation by air at high temperatures is inferior to that of nickel-base alloys. Zirconium alloys as brazing materials are considered. Shear strength of joints in Nimonic 75 strip brazed at 2100 F with Zr-1 W powder is 33,700 psi at 1690 F. Tables, photomicrographs.—INCO. 11987

5.3.4

The Effect of the Catalytic Ion in Obtaining Crack-Free Structures in Chromium Plating. H. L. Kee. *Ind. Finishing,* **9,** No. 93, 426-430 (1956) March.

Tests with various inorganic and organic additions to a plating solution of 250 g/l chromic acid. All observed deposits were cracked or black. Some of the results obtained on the conventional solution containing 2.5 g/l sulfuric acid conflict with those obtained by other workers.—BNF. 12046

5.3.4

The Electrodeposition of Tungsten. G. L. Davis and C. H. R. Gentry. *Metallurgia,* **53,** No. 315, 3-17 (1956) Jan.

A survey of work on the electrodeposition of tungsten and its alloys from aqueous, organic and fused salt baths: only from fused salt baths, the most promising being $Li_2B_2O_4/K_2B_2O_4$ (or $Na_2B_2O_4$)/WO_3, have thick coherent layers been obtained. It is difficult to find suitable vessels for containing such a melt. Theoretical aspects of electrodeposition from fused salt baths are treated in detail, stressing the future importance of such baths for the extraction and electrodeposition of many refractory metals. 49 references.—BNF. 11951

5.4 Non-Metallic Coatings and Paints

5.4.2

Application of Enamel as a Protection for Aircraft Material. P. Midol. *Corrosion et Anti-Corrosion,* **4,** 60-66 (1956) Feb.

Application of enamel coatings to impart high-temperature corrosion-resistance, particularly to vanadium pentoxide attack, sulfur dioxide and trioxide and carbon monoxide and carbon dioxide in gas turbine and piston engines. Supporting data are given on plain and enamelled Inconel and NS-20-C and NS-21-S stainless steels.—INCO. 12064

5.4.2

Influence of Copper Ions on Adherence of Vitreous Coatings to Stainless Steel. D. G. Moore and A. G. Eubanks. National Advisory Cttee. for Aeronautics, Tech. Note No. 3679, February, 1956, 14 pp.

Copper ions in vitreous coatings on AISI Type 321 steel produced a significant increase in adherence on both pickled and sand-blasted surfaces but the effect of the copper decreased with increased firing temperatures and increased firing time for the pickled specimens. X-ray examination of specimens revealed that the copper ions were reduced to metallic copper near the interface during firing but examination of sections with the metallographic microscope showed no selective corrosion of the stainless steel surface. Illustrations.—INCO. 12062

5.4.2

A Radioisotope Study of the Nickel Dip. J. C. Richmond, H. B. Kirkpatrick and W. N. Harrison. Paper before Am. Ceram. Soc., 55th Ann. Mtg. New York, April 29, 1953. *J. Am. Ceramic Soc.,* **39,** No. 2, 39-46 (1956) Feb.; U. S. National Advisory Cttee. for Aeronautics, Tech. Note No. 3577, February, 1956, 26 pp.

Radioisotope tracer studies of the deposition of nickel during nickel dipping of steel and of the effect of this nickel deposit on the reduction of cobalt ions to metallic cobalt during enamel firing showed the following: deposition of nickel on the metal surface during the dipping and the deposition of cobalt at the enamel-metal interface during firing were both markedly affected by the type of cleaning given the steel and by the mechanical deformation of the metal surface; the nickel from the nickel dip remained as metal at the interface during firing of the enamel; and the presence of the nickel deposit had little or no effect on the deposition of cobalt at the interface during firing.—INCO. 12117

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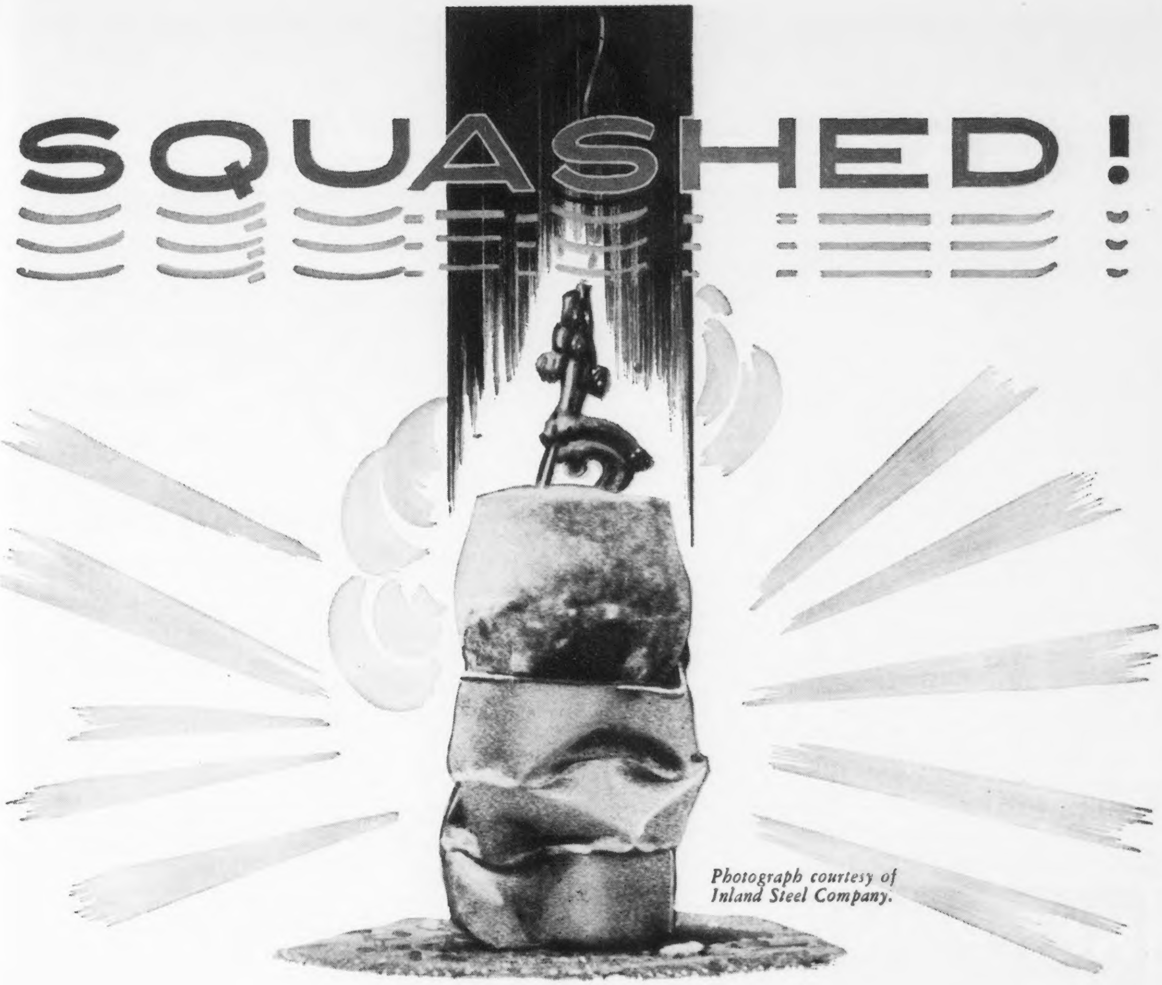

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5.4.5

Protection with Anti-Rust Paints Containing Zinc Powder. (In Italian.) G. BINETTI. *Metalludgia Italiana,* **48,** No. 3, Atti notizie Section, 71-86 (1956) March.

After discussing the mechanism of rusting and the protection given by zinc-rich paints, gives results of atmospheric and accelerated corrosion tests and potential measurements.—BNF. 11954

5.4.5, 5.4.10, 8.9.3, 5.2.1, 2.3.4

Testing Wrappings on Cathodically Protected Submerged Pipe and Fittings. H. M. CLAYTON. *Corrosion,* **12,** No. 9, 455t-458t (1956) Sept.

All 20-mil tapes failed when tested by the Light, Gas & Water Div. of Memphis, Tennessee in 2000 ohms/cm^3 water wrapped over 1-inch pipe carrying impressed voltages of —.85 to —2.5. Ten-mil tapes performed better. The principal reasons for failure were poor adhesives and tape elasticity and memory which tended to pull away wrappings over elbows and caps. Coal tar enamel tested under the same conditions performed well.

Test equipment included a device for measuring the conductivity of the water and a transparent plastic box in which the tested samples were submerged. Close check was kept on applied potentials. A record was kept of water absorbed by the wrappings. It is believed increased current flow was caused by water creeping under tapes rather than by absorption.

Tests were run for periods of eight weeks gradually increased voltages having the effect of accelerating the tests. Data are graphed for typical tests and a table of data on a typical sample is given. 12089

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5.4.5, 8.10, 2

Painting of Steel Structures in Iron and Steel Works. LORENZ BIERNER. *Stahl und Eisen,* **76,** No. 6, 335-344 (1956) March 22.

Report No. 179 of the Committee of Mechanical Engineers of the Verein Deutscher Eisenhuttenleute. The importance of the expenditure for and of securing the quality of paint coats in the iron and steel works. Factors which—apart from the quality and the suitability of the painting medium—determine the life of a paint coat. Discussion of the question, whether the prescription of definite paint formulas contributes to securing the quality of the paint coat or not.—SE 11953

5.4.8

Oil-Soluble Organo-Metallic Compounds. M. A. PHILLIPS. *Chem. Age,* **74,** No. 1906, 243-244 (1956).

The higher alkyl derivatives of succinic acid form metal complexes with bismuth, arsenic, antimony, copper, mercury and such organo-mercury residues as PhHg. These metal complexes are oil-soluble and can be incorporated into ointments and insecticides and into paints as fungicides.—RPI. 12104

5.4.8, 2.3.7

Recent Experiences with Butyl Titanate for Paint Purposes. G. SACHS AND F. WERTHER. *Schweiz. Arch. angew. Wiss. u. Tech.,* **22,** No. 3, 75-84 (1956) March.

For heat resistant coatings for interior use (up to 650C) and for outdoor use (up to 500C) the following paint system is recommended: two primers of polymeric butyl titanate with superfine zinc dust and two finishing coatings of polymeric butyl titanate with extra fine aluminum flake (50-150$_\mu$). Pretreatment and test apparatus to prove the corrosion resistance and adherence of the paints are described. The monomeric butyl titanate is chiefly recommended as a blending agent for different vehicles. The adherence and resistance to temperature changes of the aluminum pigment coatings with polymeric butyl titanate base is said to be outstanding.—ALL. 12129

5.8 Inhibtiors and Passivators

5.8.2, 4.6.2

Hydrazine Application as Binder of Rest Oxygen in High Pressure Boiler Feed-Water. (In German.) W. NISSEN. *Energietechnik,* **6,** No. 3, 108-112 (1956) March.

Chemical properties of hydrazine. German and foreign experience in use as a corrosion inhibitor. Effect of temperature. Corrosion preventive action. 8 references.—BTR. 12084

5.8.2, 7.3

Which Chemical-Pump System for Your Plant? G. E. SHAFFER, JR. Milton Roy Co. *Power,* **100,** No. 4, 88-90 (1956) April.

Discusses proper pumping systems for various internal water treatments such as sodium sulfite injection, hydrazine injection, sodium phosphate injection, addition of excess caustic soda to sulfite or phosphate feed and addition of filming or neutralizing amines direct to boiler or steam lines.—INCO. 12146

5.8.3

Mechanism of Inhibitor Action. (In Russian.) L. I. KASHTANOV AND N. V. KAZANSKAIA. *J. General Chemistry* (Zhurnal Obshchei Khimii), **26,** No. 1, 184-186 (1956) January.

Retardation of corrosion in oxidation reactions. Inhibitors studied include hydroquinone, aniline, phenol, naphthylamines and others. Tables. 27 references. —BTR. 12034

5.8.3

Studies in Corrosion. G. H. CARTLEDGE. *Scientific American,* **194,** 35-40 (1956) May.

Technetium, the synthetic element found in the products of uranium fission, strongly inhibits the exidation of iron. This phenomenon suggests a new ex-

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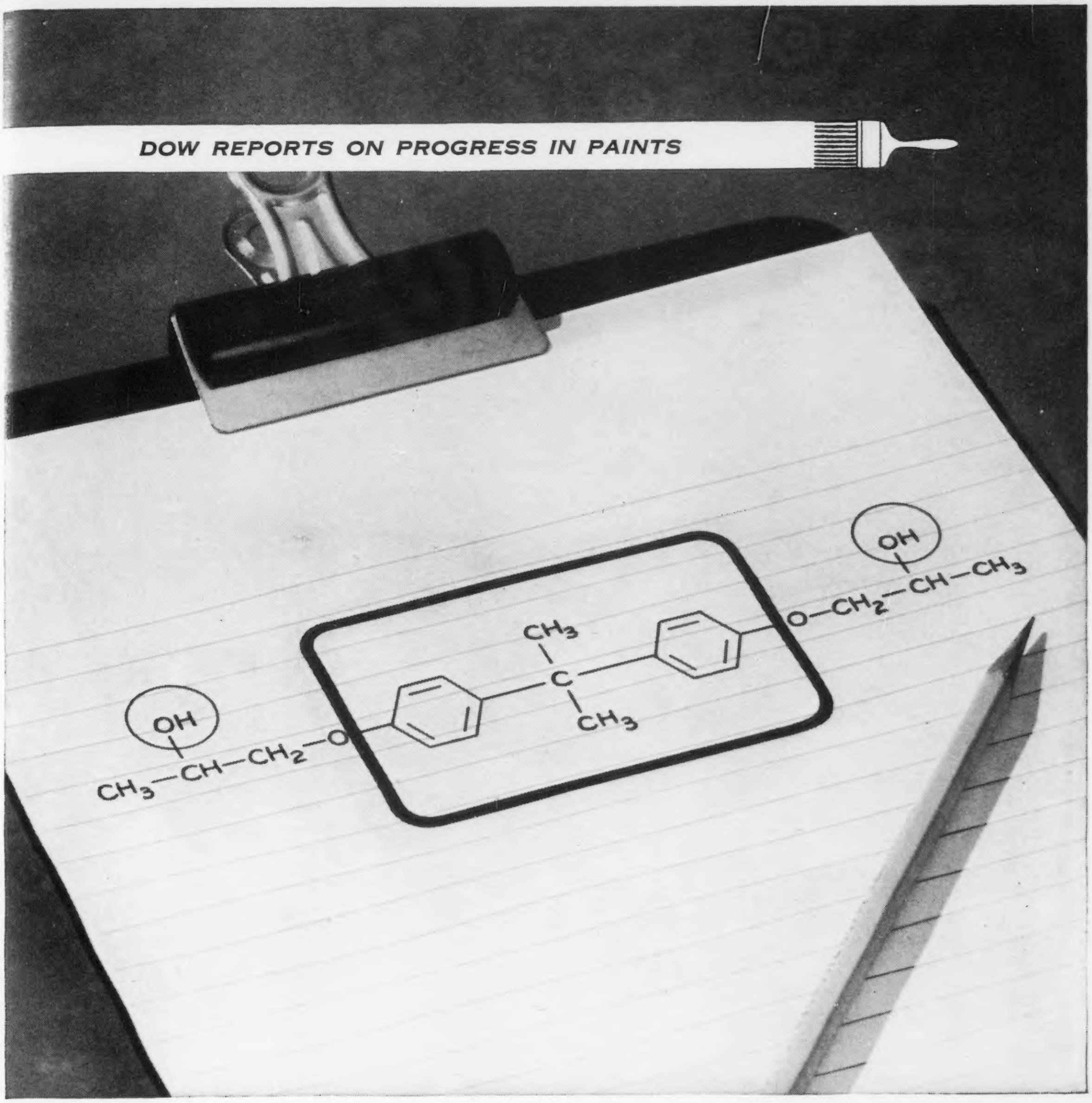

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planation for the action of corrosion inhibitors. Photographs, diagrams, micrograph, radiograph.—BTR. 11974

5.8.4

Studies on Amine-Type Corrosion Inhibitors. Rept. VIII. Secondary-Amine-Type Inhibitors in Aqueous Solution. S. Fujii and K. Aramaki. *Corrosion Engineering,* **5,** No. 2, 85-89 (1956) April.

Secondary-amine-type inhibitors, prepared by reacting 1 mol secondary-amine with 1 mol corresponding acid at elevated temperature, were tested. When fully dispersed in corrosive media, they can be more rapidly adsorbed on the metal surfaces than primary-amine-type inhibitors described in previous reports. In severely corrosive media, better inhibition is obtained with the secondary-amines. Among C_8-C_{18} amine-type inhibitors the higher ones are more protective.—JSPS. 12006

8. INDUSTRIES

8.4 Group 4

8.4.3

Corrosion Is Where You Find It. O. L. Gambrell. Paper before Natural Gasoline Assoc. of America, Ann. Mtg., Fort Worth, April 11-13, 1956. *Oil Gas J.,* **54,** No. 50, 228-242 (1956) April 16.

Corrosion detection and control in gasoline plants are done by water analyses, corrosion-rate coupons, use of non-destructive ultrasonic or radiographic instruments which measure thickness and periodic visual inspections of equipment. Discussion of an efficient procedure for corrosion detection from the economic viewpoint is presented and a corrosion survey of a typical gasoline plant is given as an example. Illustrations.—INCO. 12026

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8.4.3, 5.8.2

Squeezing Inhibitor Into Formation. R. H. Poetker and J. D. Stone. Sunray Mid-Continent Oil Co. *Petroleum Engineer,* **28,** B29-34 (1956) May.

Corrosion in gas lift wells has been reduced by squeezing inhibitors back into the formation. Treating costs in the Placedo field of Victoria County, Texas were cut 49.9% and treating efficiency was increased 16.9%. This method as compared with batch treatment has been tested and studied and tables showing comparison of various chemical treatments on corrosive wells are given along with interesting details of results. It is pointed out that the method is still in the experimental state and considerable care should be taken in doing a squeeze job.—VISCO. 12098

8.5 Group 5

8.5.4, 8.5.3

Today's Thinking on Groundwood Mill Maintenance. J. A. McLean. Great Northern Paper Company. *Paper Trade J.,* **140,** No. 15, 24-27 (1956) April 9.

Discusses methods and machinery used in extraction of fiber from wood. Stainless steels are preferred machinery materials because of superior machining and wear and corrosion resistance properties. Maintenance methods for all machinery involved are discussed. Photos. —INCO. 12112

8.9 Group 9

8.9.3, 5.4.10

Experience with Tape Coatings for Protection of Distribution Piping. F. Buck. Paper before Pacific Coast Gas Assn., Tech. Section Mtg., Santa Monica, Feb. 28-29, 1956. *Gas,* **32,** No. 4, 92, 94-95 (1956) April.

Discussion covers the use of plastic tapes for field joints on service piping. Application of tapes as to training, joint preparation, primers, overwrap, handling and bonding is described. Results of investigation showed that the product should be long lasting, economically applied, moisture-, electrical-, mechanical- and biological-resistant and cold applied with a good bond.—INCO. 11950

8.9.4

The Protection of Metals in Railway Service. F. G. Dunkley and W. J. Hair. *Electroplating & Metal Finishing,* **9,** No. 3, 77-81 (1956) March.

Surface preparation is accomplished by acid pickling, grit blasting or flame cleaning. Proprietary phosphate treatments are used for inside surfaces of all-steel welded passenger coaches. Aluminum alloys in Diesel cars are given chemical conversion coating or etch primer and aluminum fittings are anodized. Galvanizing of track components and signalling equipment requires heavy bituminous protection in tunnels. Chromium plating of steel and brass car fittings is not satisfactory. Metal spraying is used for auxiliary signal equipment. Choice of paint systems and special problems encountered in painting of stations, bridges, freight and passenger cars and structural steel work are considered.—INCO. 11985

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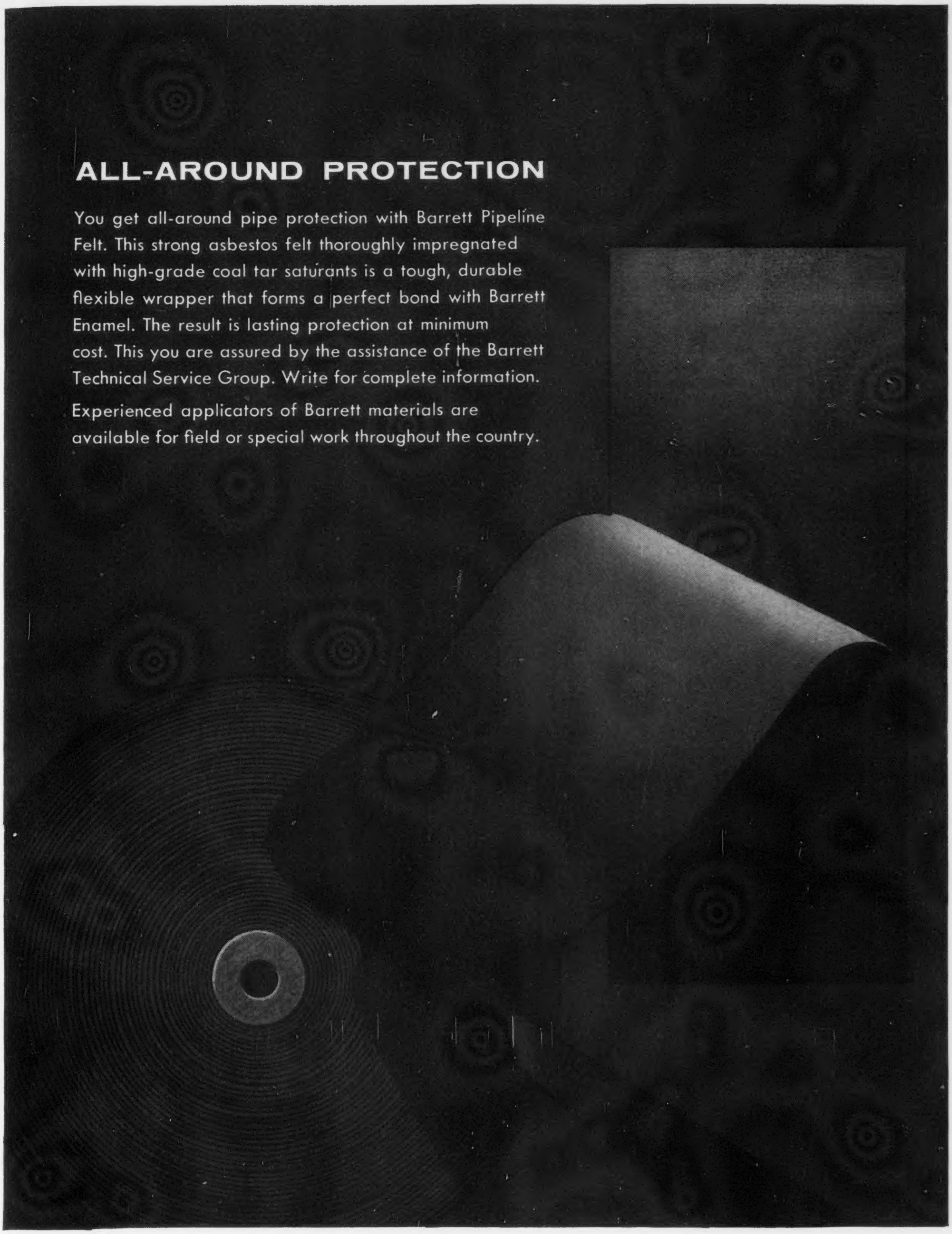

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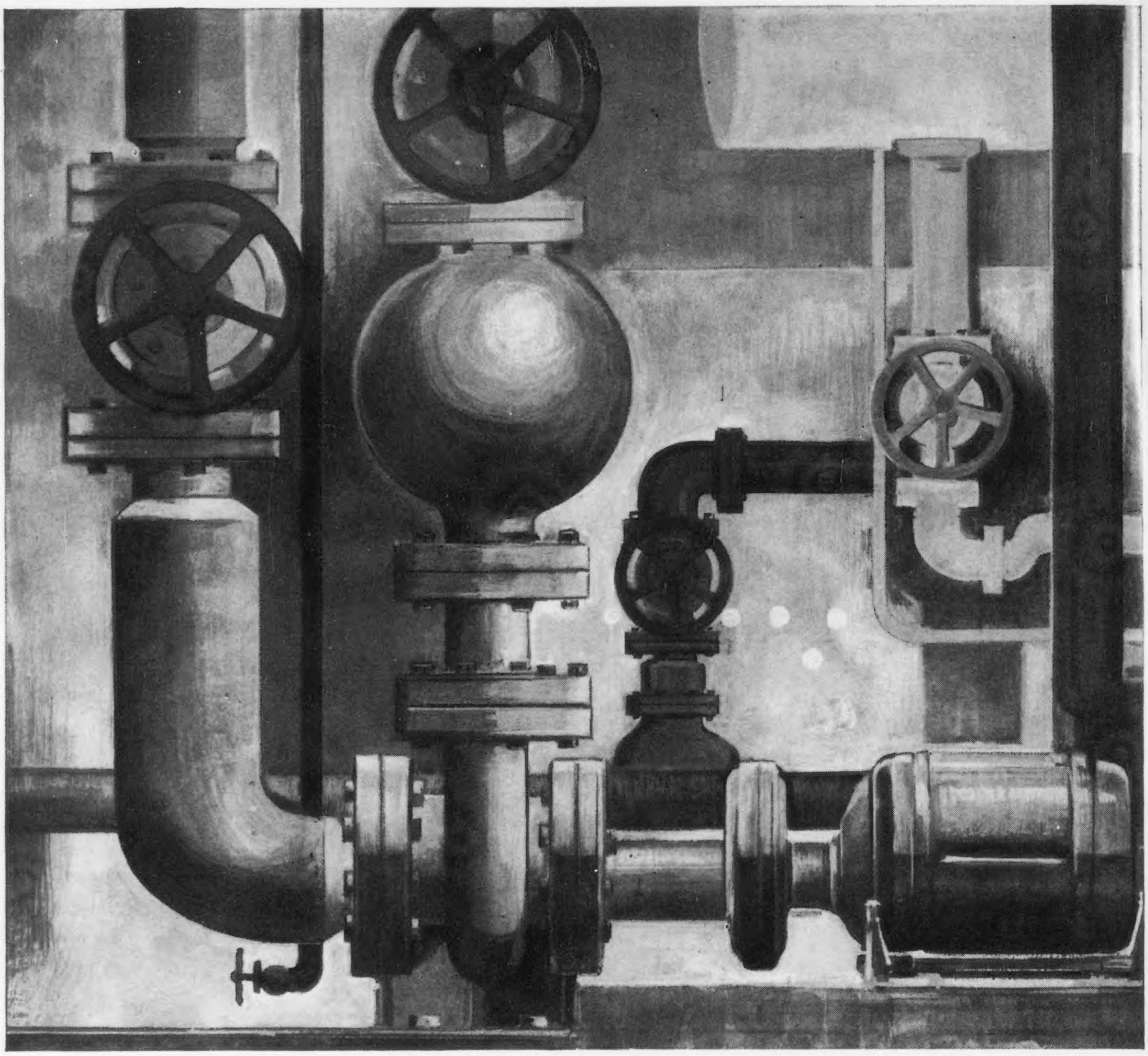

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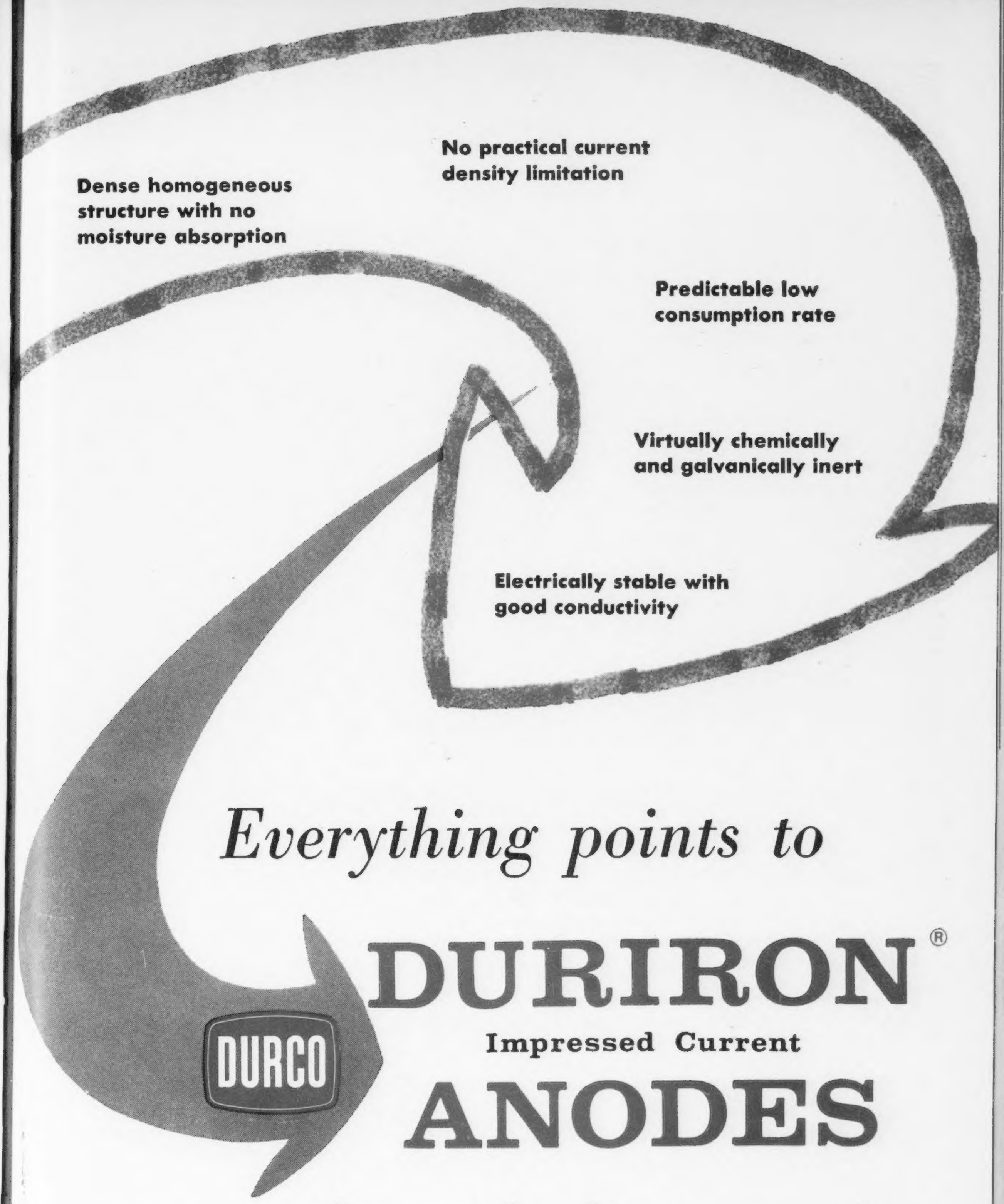

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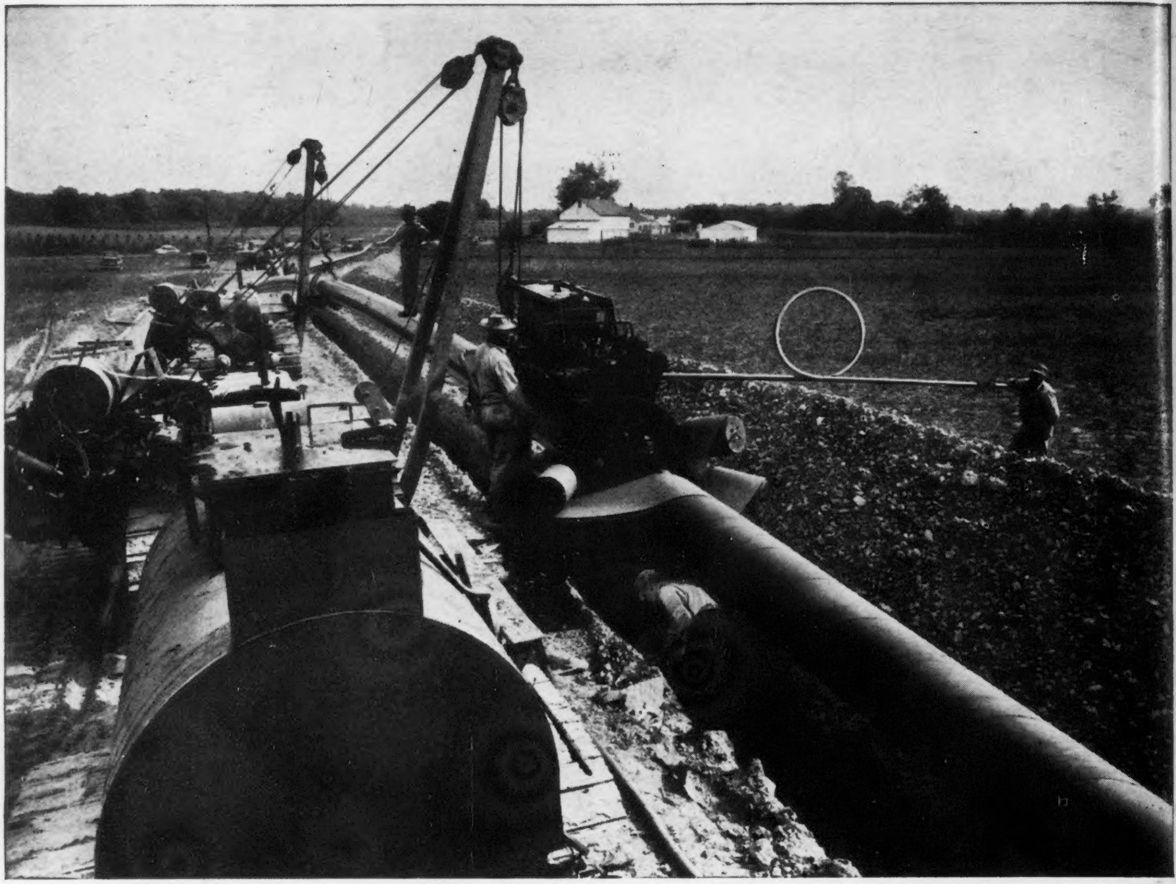

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